CEC AGRICULTURAL PEAK LOAD REDUCTION PROGRAM - WATER AGENCIES - FINAL REPORT

CONSULTANT REPORT

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LEGAL NOTICE

EXECUTIVE SUMMARY

The Program

During the winter of 2000-2001, California experienced a severe imbalance in electricity supply and demand that resulted in blackouts and brownouts. The state legislature initiated a number of emergency programs, one of which was Senate Bill 5x. The primary goal of SB 5x is to reduce peak period electric demand throughout California. The California Energy Commission (CEC), acting under authority of Section 5(b) of the legislation, developed the "Agricultural Peak Load Demand Program". The program was funded in early June 2001, and the Irrigation Training and Research Center (ITRC) of California Polytechnic State University (Cal Poly), San Luis Obispo was contracted to administer the agricultural water agency portion of the program for CEC.

Prior to the program announcement in early June 2001, ITRC sent a Statement of Interest to over 100 major agricultural water agencies in California about participating in a load reduction program. Because of this, many agencies already had begun planning projects for participation. Almost immediately after the bill was funded, a description and applications for the different portions of the program were also sent to all agricultural water agencies in California.

The Agricultural Peak Load Reduction Program (APLRP) had four main categories:

- Category 1 - High Efficiency Electrical Equipment/Other Overall Electricity Conservation Efforts
- Category 2 - Pump Efficiency Testing and Retrofit/Repair
- Category 3 - Advanced Metering and Telemetry
- Category 4 - Retrofit of Natural Gas-powered Equipment to Alternative Fuels

Water agencies utilized Category 1 mainly to construct or expand storage reservoirs to supply water users during the peak period (12 pm-6 pm, Monday-Friday, June-September), using either gravity or a lower pumping demand than would have been used in the original distribution system. The reservoir is then refilled during off-peak periods. Other projects included installation of variable frequency drives (VFD), replacing well casing so groundwater pumps can be shut down and started on a daily basis without damage, and some innovative solutions that were used to reduce peak load demands throughout California.

Category 2 provided water agencies with incentives, in the form of rebates, to have pumps tested and retrofitted/repaired if desired. Within the pump testing section of the program, stringent requirements were developed, which the pump test companies to had follow in order to qualify for a rebate. ITRC conducted 3 pump test training courses throughout the duration of the program where pump testers could learn hands-on how to conduct a pump test using these guidelines.

Category 3 provided incentives for the installation of advanced metering and/or telemetry necessary to reduce peak load. Most projects that utilized this category were provided grants to assist in the capital cost associated with participating in California ISO Demand Relief Program. Other agencies used Category 3 grants to install telemetry on key parts of their distribution systems. The telemetry allowed the agencies to remotely monitor and control parts of the distribution system so that they would be able to curtail peak load. Generally, these agencies had enough existing capacity in reservoirs and pumping stations to shift a significant amount of peak load. However, the telemetry was a necessary component to assist operators with fluctuations in flow rates from different sources and allow them to shut down and turn on pump stations from one central remote location.

California water agencies did not take part in any Category 4 projects; therefore, this category will not be discussed further in this report.

Results and Discussion

From June 2001 to May 31, 2004, the agricultural water agencies voluntarily participated in load shifting, utilizing approximately $5.7 million in cost-sharing grant money and curtailing nearly 42 MegaWatts of demand. In addition, 1,155 pumps were tested and pump repairs were made to 299 pumps, resulting in an estimated savings of 21 million kWh. The following table is a summary of the Agricultural Peak Load Reduction Program Results.

Table ES-1. APLRP Complete Summary of Results

Category	Value of Grants Paid	kW **Peak** Demand Reduction	Grant $/ peak kW Reduction	**Annual** kWh Reduction
1a – High Efficiency Electrical Equipment/Other Overall Conservation Efforts	$2,083,133	16,495	$126	
1b – Fuel Switching Rebate	$205,000	820	$250	
2 – Pump Efficiency Testing and Pump Retrofit/Repair*	$2,356,000			21,010,962
3 – Advanced Metering and Telemetry	$899,367	25,392	$14	
Totals*	$5,543,500	42,707		21,010,962

*An additional $144,000 was used for pump test training conducted by ITRC for pump testers throughout California. These funds were from Category 2 bringing the value of grants paid in Cat. 2 to $2,500,000 and the total value of grants paid to water agencies to $5,687,500.

The Agricultural Peak Load Reduction Program objective was to reduce the peak load demand in agriculture throughout the state of California. Water agencies throughout California exceeded expectations in regard to curtailing peak load and were able to do this with lower-than-expected funding.

Category 2 was the most popular category in the program. Water agencies received benefits using a relatively simple application process and for relatively low capital costs. Pump retrofit/repair projects usually had a payback period of less than 2 years. Many of the districts that participated in this category did not feel they could feasibly participate in Category 1 or 3 projects.

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INTRODUCTION

Background

Near the end of 2000, utility companies such as Pacific Gas & Electric and Southern California Edison, presented their dire financial situations to the state government. The companies explained that to keep electricity supplied for the State of California, electricity rates would have to be increased dramatically or government assistance (financial) would be necessary. However, the problem extended beyond the financial limitations of the electric service providers. Since California consumes a relatively significant quantity of energy in comparison with neighboring states, the need for a solution was heightened by an imbalance between supply and demand.

In response to California's energy crisis, Senators Byron D. Sher (D-Stanford), Richard Alarcòn (D-San Fernando Valley), and John Burton (D-San Francisco) introduced a bill entitled "State Energy Projects" (Bill Number: S.B. No. 5 (1st Ex. Session)). The bill was very broad in scope, and intended to reduce the electrical energy consumption of the state by providing funding for:

1. Projects implemented that reduce the peak electrical load, defined as 12 noon–6 p.m., Monday–Friday, June–September, excluding holidays.
2. Projects implemented that increase the overall efficiency of the particular process.

Within three months of introduction, the governor approved the bill, thereby allocating funding to various agencies to implement the program in the "most expedient manner possible." The urgency with which the bill was undertaken is further expressed in the last paragraph of the bill:

> "Due to the shortage of electric generation capacity to meet the needs of the people of this state and in order to limit further impacts of this shortage on the public health, safety, and welfare, it is necessary that this act take effect immediately."

Of particular interest to the agricultural sector's electricity consumption is Section 5 of the bill (**Appendix B**), which allocated a total of $75,000,000 in grant funding. The official name of this section was entitled the Agricultural Peak Load Reduction Program (APLRP). Charged with the management of the program, the California Energy Commission (CEC) delegated administrative responsibilities for the California water agencies component of the program to the Irrigation Training and Research Center (ITRC) at California Polytechnic State University, San Luis Obispo (Cal Poly), and administrative responsibilities for the on-farm component of the program to the Center for Irrigation Technology (CIT) at California State University, Fresno. ITRC's role was to provide water agencies throughout the state with information on the program and, when required, technical assistance for project development. In addition, ITRC reviewed the applications to determine whether the projects were reasonably feasible and met the standards set forth in the program.
To differentiate between the possible types of projects and resulting rebates, the program was broken down into four categories:

- Category 1 - High Efficiency Electrical Equipment/Other Overall Electricity Conservation Efforts
- Category 2 - Pump Efficiency Testing and Retrofit/Repair
- Category 3 - Advanced Metering and Telemetry
- Category 4 - Retrofit of Natural Gas-powered Equipment to Alternative Fuels

The legislation was passed in April 2001, with the desire to reduce peak electric loads immediately – to avoid summer power brownouts and outages. Contracts between CEC and ITRC were not completed until late May. Guidelines were developed, the application process was written, quality control measures implemented, verification procedures defined, and the first set of program descriptions and applications were sent to the water agencies on June 1, 2001.

Program Schedule and Promotion

ITRC and CEC had discussed this project since December 2000, because the legislature needed to have some idea of how much money was needed for irrigation districts. ITRC had canvassed the major California irrigation districts for information, and had informed them that this program was in the works. Therefore, many of the districts were ready to act almost immediately – even if the application process had not yet been refined.

The first application sent out was primarily for Category 1 and 3 projects, which required a contract with Cal Poly, although the Category 2 rebate program was also incorporated into this application to eliminate the need for multiple applications. By mid-June 2001 it was apparent that this single application was confusing to Category 2 applicants. The initial application was simplified to only incorporate Category 1 and 3 non-rebate projects and separate rebate applications and requirement information packets were developed for both Category 2 Pump Efficiency Testing and Pump Repair/Retrofit projects. The new applications and information packets were sent to every agricultural water agency in California and interested pump testing companies in early July 2001.

Applications were simplified as much as possible and the information packet that accompanied each application contained step-by-step instructions and examples to help with the application process. The applications and information packets were sent as hardcopies to all water agencies, as well as through email to water agencies that had email addresses. The most up-to-date applications were also available to download at the ITRC website.

In mid-June 2001, every water agency that had received an application was given a courtesy call by ITRC to determine their level of interest in the program and to offer technical support. Interested water agencies were again called in late July and again in September and offered technical assistance. Many agencies were unable to think of projects that would reduce their peak load. In response, ITRC put together a single newsletter that contained case studies of water agency projects that had been approved under the CEC APLRP. The newsletter was sent to each water agency and published on the ITRC website.

In October 2001, Category 1 was expanded under the CEC APLRP to include a new type of project: converting from electricity to natural gas, propane, or an alternative fuel such as biogas. This was termed Fuel Switching and a rebate application was created specifically for this type of project and sent to water agencies throughout California.

The APLRP program ran from June 1, 2001 through December 31, 2004. Applications were accepted from June 2001 until December 31, 2003 for all categories. The completion deadline for projects was May 31, 2004. Final verification of project completion and actual peak load reduction for all projects was completed by December 2004.

PROGRAM DESCRIPTION AND APPLICATION PROCESS

The overall Program Description for Water Agencies was written by ITRC and approved by CEC. Minor modifications were made throughout the program timeline, as described above. These modifications generally consisted of modifications to dates and the application process. The latest version of the Program Description for Water Agencies can be found in **Appendix A**.

All projects were limited to installations that had an existing connected electric load with a history of electricity consumption. Projects were approved on a first-come-first-served basis.

Category 1 - High Efficiency Electrical Equipment/ Other Overall Electricity Conservation Efforts

This category has two main components:

1a. <u>Category 1 non-rebate projects</u>. The majority of projects in this category entailed construction of storage reservoirs to which water could be pumped during off-peak hours and which would then supply demands using gravity during the on-peak hours.

1b. <u>Category 1 Fuel Switching rebate projects</u>. This type of project is limited to either replacing existing electrical equipment using grid power, with new equipment using natural gas or propane, or keeping the existing electrical equipment but replacing the grid power with power from new natural gas or propane generators. However, for any new equipment (such as a combustion engine or microturbine, and including generators), in order to be considered an increase in efficiency the input kW of new equipment must be less than the original input kW.

<u>Cost Sharing</u>

For non-rebate projects in Categories 1, the grant could pay up to 65% of the project cost. The maximum reimbursement per kilowatt (kW) load reduction depended upon the date of project implementation, as a means of encouraging quick implementation of the projects. The reimbursement could be up to $350 per kW for projects completed by July 31, 2001, $300 by September 30, 2001, and $250 by May 31, 2004.

For Category 1 Fuel Switching rebate projects, the grant could also pay the lesser of up to 65% of the project cost, or $250 per input kW taken off-line.

Application and Verification Process

Category 1a. The program was designed as follows for Category 1 non-rebate projects:

1. Districts submitted the application forms directly to ITRC for technical review and determination of eligibility and administrative completeness.
2. ITRC reviewed the applications and defined the steps and data that would be needed for verification.
3. The program administrator for CEC was asked for approval; this approval was given within a few days. The district was given an e-mail or verbal approval to proceed – with financial reimbursement pending approval of the final contract.
4. The irrigation district was sent a contract document from ITRC. Technically, the contract was between the district and the Cal Poly Foundation. This is a key aspect to the program – by contracting directly between Cal Poly and the irrigation districts, the typical state paperwork and processing lag times were eliminated.
5. The contract document was signed by the district and returned to ITRC. The project received final approval.
6. Payment of 50% of the estimated incentive grant payment was made after completion of construction and full operations. Copies of all invoices, service contracts, personnel time records, and other relevant information were required to prove the final installation of the project.
7. The final grant payment was made after verification of the project's actual peak period demand reduction. This generally required one full peak period of operation (June through September) after construction had been completed.

In general, the Category 1 application process required a shortened but typical engineering application requesting historical information on peak electricity consumption, a plan for reduction of the peak load, a cost analysis, and agreement for verification. The districts did an excellent job of submitting high quality applications. Several consulting engineering firms actively worked with their clients to fill out the applications.

Challenges included determining the proper verification techniques, and in deciding exactly how to compute the eligible kilowatts (kW). For example, if a pump is only operated 5 hours per year during the peak period, it did receive the same rebate as one operating several hundred hours. Fortunately, the majority of the Category 1a projects' load reductions were on large pump stations where pumps were equipped with time-of-use meters and a historical basis of peak energy usage could be established. Dividing the peak energy usage (kilowatt-hours (kWh) for June – September) by the total peak number of hours gives the peak load (kW) for that year.

In addition, 2001 was a dry year, meaning that some irrigation districts pumped more during 2001 than they had during previous wetter, years. Verifying peak load reduction comparing two different types of years can be misleading. Therefore, districts were allowed to use any *justifiable* historical year as a baseline. For example, North Kern Water Storage District used 1992 power records to create their historical baseline because precipitation and deliveries to the district in that year more closely resembled the post-project verification year (2001).

Category 1b. The program was designed as follows for Category 1 Fuel Switching rebate projects:

1. Prior approval was required for these rebates. Approval required documentation of certain items, including pre-project input kW to existing electrical equipment, fuel consumption rate of the proposed equipment, and computations showing the potential rebate.
2. Project eligibility was ascertained by converting the fuel consumption rate of the proposed equipment into an equivalent kilowatt (kW) load. Conversion factors were determined by ITRC for natural gas and propane to convert fuel consumption to

equivalent input kW. If the equivalent input kilowatts from the proposed equipment were less than the existing input kilowatts, the project was eligible for a rebate and pre-approval was granted.

3. Verification of project completion and final invoices showing the total project cost were required for final approval.

Category 2 – Pump Efficiency Testing and Pump Repair/Retrofit

Cost Sharing

For Category 2 pump testing projects, the program reimbursed up to 80% of the total pump tests, up to $200 for a "standard" test, and up to $250 for a special test requiring two transects of data for flow measurement.

Pump repair cost sharing consisted of either the maximum value of one of the three rebate calculation options (listed below) or 65% of the project cost, whichever was less. For example, if Option 3 granted the highest rebate of the three options and was less than 65% of the total project cost, the applicant would receive the Option 3 amount. If Option 3 were greater than 65% of the project cost, the applicant would receive 65% of the project cost. Below is the list of rebate calculation options and the required documentation needed for each:

Option 1:

$$\boxed{\text{Rebate} = \$300 \times \left[\frac{\text{4 month hours}}{2928}\right] \times \left[(\text{Pre kW}) - (\text{Post kW})\right]}$$

Where:

- 4 month hours are the hours of operation of a pump from June – September, established by electrical billing records.
- Pre kW is the input kilowatts (kW) to the electrical motor, based on a measurement of pre-input kW.

- Post kW is the input kilowatts (kW) to the electrical motor, based on a measurement of post-input kW.

Option 2:

$$\boxed{\text{Rebate} = \$.1025 \times \left[1 - \frac{\text{Post}\,\dfrac{\text{kWh}}{\text{AF}}}{\text{Pre}\,\dfrac{\text{kWh}}{\text{AF}}} \right] \times (4\,\text{month hours}) \times \text{kW}}$$

Where:

- 4 month hours are the hours of operation of a pump from June – September, established by electrical billing records.
- Pre kWh/AF is the kilowatt-hours per acre-foot (kWh/AF) consumed by the electrical motor, based on a pump efficiency test before the repair occurred.
- Post kWh/AF is the kilowatt-hours per acre-foot (kWh/AF) consumed by the electrical motor, based on a pump efficiency test after the repair occurred.
- kW is the input kilowatts to the electrical motor, based on a measurement of pre-input kW.

Option 3:

$$\boxed{\text{Rebate} = \$0.10 \times 0.25 \times kWh}$$

Where:

- kWh are the annual kilowatt-hours of the pump, established by electrical billing records (can also be determined as Input kW multiplied by the annual hours of operation).
- Impeller repair or replacement is required to use this option.

Application and Verification Process

Pump Efficiency Testing. Analysis required a comprehensive knowledge of the methods required for a pump test, as well as the calculations to determine the desired values, which describe the status of the pump to a pump repair professional. Necessary equations for given data resulting from a pump test are illustrated in the Floway Turbine Data Handbook. The procedure by which a pump efficiency test was reviewed and analyzed is as follows:

1. Applications for a pump efficiency testing rebate were sent to ITRC, generally by a pump efficiency testing company, in the format required by the program guidelines (**Appendix B**).
2. The pump efficiency tests were reviewed to ensure that an accurate test had been performed according to the standards and that the calculations for particular data were correct.
    a. Not necessarily all of the pump tests were reviewed for every single piece of data; rather, tests were selected randomly, and particular attention was paid to key data values (i.e., total dynamic head, overall pumping plant efficiency, kWh/AF, input kW, etc.).
    b. Every picture submitted came under scrutiny, because an important element of the program was to ensure that the efficiency tests were conducted with minimal influence from obstructions within the pipe. An acceptable pump set-up would be similar to what can be seen in **Figure 1**. The pictures were essential to confirm that 1) the pump existed, and 2) that the minimum distance velocity measurement requirements were fulfilled (Table 1, Pump Efficiency Testing Application, **Appendix B**).
    c. Tests that did not meet the criteria set forth in the guidelines or did not pass a "reasonableness test" (i.e., if the picture indicted that the minimum distance requirements were not met or if the pump was stated to have a maximum efficiency of 85% - an unrealistic efficiency) did not qualify for a rebate.

Figure 1. Using an ultrasonic flow measurement device during pump efficiency test.

Pump Repair/Retrofit. Analysis of acceptable applications for the pump repair component of the program required comprehensive knowledge of how to interpret the data from a pump efficiency test and make a general indication of the options for repair. Review of the data provided by water agencies or pump repair professionals could be performed in the following manner:

1. The district or repair company submitted the pre-approval application for a pump repair rebate to ITRC for initial review. The purpose of this initial review was to:
    a. Secure an amount of funding for the repair based upon the lesser amount of either 65% of the estimated total project cost or one of the three estimated rebate options (previously discussed).
    b. Ensure that the repairs indicated on the application were acceptable according to the program guidelines (**Appendix B**).
2. Upon completion of the project, the water agency or pump repair company submitted the electrical billing records, post-repair pump efficiency test (if required) and invoices for project expenses.
3. The type of work, including the repairs performed on the pump, shaft, motor, etc., were reviewed under close scrutiny to ensure that the repairs indicated in the pre-

approval process were completed and that no "hidden" or additional charges, that did not fall under the scope of the program, were included.

Grants were made for pump repairs, pump bowl/impeller lining, motor or pump replacement and other actions to improve pump efficiency (not to include motor rewinding, unless it was necessary for proper operation of a VFD). In addition, well cleaning that reduces drawdown and removal/replacement of valves and fittings with high-pressure losses were considered. To qualify for the incentive for motor replacement the new motor had to be rated "High Efficiency Premium".

Pump Test Training

ITRC developed a 2-day class that was offered three times throughout the duration of the program. The class included classroom and laboratory activities that focused on safety, obtaining the input kW and power factor, and measuring the flow rates. A complete training manual accompanied the class. While this class was not mandatory, it was attended by almost all of the pump testers. At the end of the class a comprehensive exam was given. ITRC and CEC only acknowledged if a person had passed the exam or not; this was not a certification for the pump tester. Both inexperienced and experienced pump testers passed the exam; likewise, both inexperienced and experienced pump testers failed the exam.

Category 3 - Advanced Metering and Telemetry

This program has been implemented for two main purposes, each purpose has different verification requirements. For simplicity, in this report the two main purposes are as outlined below:

3a. <u>To assist the water agency in continuous peak load reduction by allowing the agency to monitor and control remote sites manually or automatically from a central office</u>. Water agencies that were able to participate in this type of program either had enough existing capacity to remove peak load, or participated in Category 1 projects to increase their capacity but also needed advanced metering and telemetry to assist in the peak load reduction through remote monitoring and control.

3b. To assist the water agency with the capital cost associated with participation in the California ISO (Independent Systems Operator) Demand Relief Program (DRP). In order to participate in the DRP, the district needed to install real-time electric meters and a cellular modem so that the immediate load could be accessed remotely.

Cost Sharing

Both types of projects had the same cost sharing, which is the same as Category 1 non-rebate projects: The grant could pay up to 65% of the project cost. The maximum reimbursement per kilowatt (kW) load reduction depended upon the date of project implementation – as a means of encouraging quick implementation of the projects. The reimbursement was $350 per kW for projects completed by July 31, 2001, $300 by September 30, 2001, and $250 by May 31, 2003.

Application and Verification Process

For both types of Category 3 projects the application process was also the same as for Category 1 non-rebate projects (see steps 1-7 in Category 1a. Application and Verification Process). However, the verification process was different between Category 3a and 3b:

Category 3a. The verification was the same as Category 1a projects. In order to verify peak load reduction, pre-project peak load was compared to post-project peak load for similar operational years.

Category 3b. This program did not require documentation of actual load shifting (i.e., comparison of pre- and post-project peak load). It merely required verification of a contract between the agricultural water agency and the ISO (or subcontractor such as Ancillary Services Coalition), and the installation of the new metering or telemetry equipment or both.

RESULTS

Category 1a - High Efficiency Electrical Equipment/ Other Overall Electricity Conservation Efforts

There were two major categories of projects in this category:

1. Reservoirs. The majority of projects from water agencies in this category involved construction or expansion of reservoirs to supply distribution systems during the peak period. In order to conserve power, the reservoirs are filled during the off-peak period each day using the pumping system that normally supplies the distribution system. At 12 pm (noon) the pumps are turned off or reduced and the reservoir is used to supply the distribution system. At 6 pm the pumping system is turned back on to fully supply the distribution system and refill the reservoir. In order for this to be accomplished, the water agency must have enough system capacity (both pumping and conveyance) to supply both the water users and the reservoir during the off-peak period. Some agencies already had the capacity in the existing system, while others had to make modifications to their systems to accomplish this task.

2. Variable Frequency Drives (VFDs). Some VFDs (sometimes referred to as variable speed drives) were also installed under this category. It was often difficult to ascertain the peak load reduction associated with a VFD prior to installation because a VFD does not eliminate pump use during the peak hours, but it can make it more efficient, providing an alternative to eliminating pump use altogether during peak hours and using gravity-fed water from a reservoir. With a VFD, the pumps still supply the full demand downstream during the peak time.

   In order to understand the potential energy and demand savings from using a VFD one must understand the operation of pumping stations. Pump stations generally have one of two methods of operation. The pump station either supplies more water than is demanded and the excess water is then spilled back to the source or it pumps more pressure than is demanded and the excess pressure is "burned off" using a throttling valve. Both of these methods of operation waste electricity. However, the amount of spillback or throttling is rarely recorded, thus making it difficult to estimate the load savings with a VFD.

The majority of VFD projects estimated the amount of load savings by creating a relationship between the pump's load (kW) and the pump's speed. Then assumptions were made regarding how much time the pump would be running at each speed interval during the peak period. The estimated load curtailed could then be estimated.

The table below is a summary of Category 1 projects that were approved.

Table 1. Summary of Category 1 non-rebate projects.

	Projects that have been verified & TOTAL grants Paid
Total Applications*	**10**
Total Projects	**11**
Total Project Costs	**$3,954,262**
Total Grants	**$2,083,133**
Total kW Reduction	**16,495**
$/kW - Grants	**$126**
$/kW - Project Cost	**$240**

*Some applications included multiple projects

The following section contains individual summaries of the Category 1 non-rebate projects. Some water agencies participated in multiple projects through the APLRP. Many of the following projects also installed telemetry (Category 3). For simplicity, if the main component of the project fell under Category 1 it will be summarized in this section. If the main component was telemetry, it will be summarized in the Category 3 section of this report.

North Kern Water Storage District

Site

The North Kern Water Storage District (NKWSD) is located in the San Joaquin portion of Kern County and encompasses nearly 60,000 acres. The district utilizes water received from the Kern River and groundwater to supply its users.

Project 1. Addition of Reservoirs and Modification of Groundwater Pumping Wells

Project Description

The district proposed and designed a project that curtailed 5.135 MW of peak load. The application for this project was received on June 12, 2001. The project was started April 24, 2001 and fully completed August 31, 2001. The district had enough of the major construction completed by June 1, 2001 that they were able to curtail the entire 5.135 MW of peak load from June – September 2001. NKWSD received the first 50% of the grant in December 2001. Final verification was completed and the district received their final grant payment in February 2002.

Figure 2. New reservoir used to store water during the off-peak as a supply during the on-peak period

The project included the construction and use of storage reservoirs to supply water to users during the peak period, allowing groundwater pumps to be turned off. Older well casings were lined to prevent casing failure. Timers were installed on each well control panel in the program to automatically shut the well off during the peak period.

Verification

Verification of load curtailment through the peak period was completed by comparing post-project and pre-project time-of-use meter billing for the pumps within the scope of the project. If deliveries from the Kern River are below normal, the district must supplement using groundwater pumps. In 1992, the deliveries from the Kern River most closely matched deliveries during 2001 (post-project verification year). Therefore, NKWSD used power usage records for 1992 for their baseline pre-project peak load.

Project Results

Summary Category	Results
Total Project Cost	$532,623
Total Grant Payment	$346,205
Actual kW Reduced	5,135
Grant Payment per kW Reduced	**$67.42**

***<u>Project 2.</u>* Addition of Telemeter and Modification of Groundwater Pumping Wells**

Project Description

The district proposed and designed a project that curtailed 3.284 MW of peak load. The application for this project was received on October 30, 2001. The project was started December 1, 2001 and fully completed November 1, 2002. NKWSD received the first 50% of the grant in January 2003. The district had most of the project completed before May 31, 2002. Therefore, they were able to curtail the entire peak load during the 2002 peak period. The portion of the project that was not completed until November 2002 included fine-tuning their telemetry system. This did not have a significant impact on peak load reduction during this year, therefore, the final verification was completed and the district received their final grant payment in February 2003.

The peak load reduction was accomplished by equipping wells with clock timers to turn the wells off before 12 pm and back on after 6 pm. In addition, older wells were rehabilitated to withstand frequent start-ups, and modifications were made to the pump discharges to reduce the impact of operation to the landowners. The proposal also included installation of, or modification to, a siphon, pumping bays, and weirs to increase the storage capacity of regulating reservoirs, thereby reducing the peak period electrical demand. Additionally, seventeen telemetry sites were installed to monitor water levels and provide data via radio to the district office computer.

Verification

Verification of load curtailment through the peak period was completed by comparing post-project and pre-project time-of-use meter billing for the pumps within the scope of the project.

Project Results

Summary Category	Results
Total Project Cost	$1,314,434
Total Grant Payment	$813,750
Actual kW Reduced	3,284
Grant Payment per kW Reduced	**$247.8**

Berrenda Mesa Water Storage District

Site

Berrenda Mesa Water Storage District (BMWSD) is located in the southern part of the San Joaquin Valley near Bakersfield. The district receives water from the State Water Project – California Aqueduct.

Project 1. Raising Reservoir Spillway

Project Description

The district proposed and designed a project that curtailed 770 kW of peak load. The application for this project was received on October 24, 2001. The project was started January 2002 and fully completed May 2, 2002. BMWSD received the first 50% of the grant in June 4, 2002. Final verification was completed and the district received their final grant payment in July 2, 2003.

Berrenda Mesa Water Storage District has curtailed usage by 770 kW. This was accomplished by permanently increasing the height of the spillway on the Berrenda Mesa Reservoir. The existing 100 foot-wide spillway was raised 15 inches to accommodate an additional 15 acre-feet of storage capacity. The additional water is stored in the reservoir during the off-peak period and delivered for irrigation during the peak period, thereby reducing the need to pump water during the peak period. One-third (5 inches) of the proposed spillway will be used for storage of water, while the other two-thirds (10 inches) will provide a cushion to avoid spill associated with wind, fetch and operational variations. The average reduction in pumping equates to 30 cubic feet per second, or 770 kW.

Figure 3. Raised spillway in on the supply reservoir in BMWSD.

Verification

Time-of-use meters were used to verify the peak load reduction, comparing the peak period electrical use of the 2002 season with that of the 2000 season.

Project Results

Summary Category	Results
Total Project Cost	$44,237
Total Grant Payment	$28,754
Actual kW Reduced	770
Grant Payment per kW Reduced	**$37.34**

__Project 2.__ Sediment Removal from the Reservoir

Project Description

BMWSD proposed and completed a project that curtailed 3,900 kW of peak load. The application for this project was received on July 10, 2002. The project was started

September 2002 and fully completed May 1, 2003. BMWSD received the first 50% of the grant in June 10, 2003. Final verification was completed and the district received their final grant payment in December 8, 2003.

The peak load reduction was accomplished by removing sediment in their main reservoir increasing the storage capacity. The additional water was stored in the reservoir during the off-peak times and delivered for irrigation during the peak times, thereby reducing the need to pump water during the peak period.

Verification

Time-of-use meters were used to verify the peak load reduction, comparing the peak period electrical use of the 2003 season with that of the 2000 season.

Project Results

Summary Category	Results
Total Project Cost	$125,830.72
Total Grant Payment	$61,750.00
Actual kW Reduced	3,900
Grant Payment per kW Reduced	**$15.83**

Orange Cove Irrigation District – Category 1 Project

Site

Orange Cove Irrigation District (OCID) is located on the east side of the Central San Joaquin Valley southeast of Fresno. The district receives water from the Friant-Kern Canal.

Project Description

The district proposed and designed a project that curtailed 126 kW of peak load. The application for this project was received on March 4, 2002. The project was started April 2002 and fully completed May 31, 2003. OCID received the first 50% of the grant in July 21, 2003. Final verification was completed and the district received their final grant payment in July 19, 2004.

The peak load reduction was accomplished by equipping farmer-owned pumps with clock timers, flow control valves, and time-of-use meters to turn the pumps off before 12 pm and on after 6 pm. The proposal also included construction of a regulating reservoir and installation of telemetry equipment, reducing the peak load due to management practices and increased water storage. This project is considered Category 1 because installation of the regulating reservoir was the major cost of the project. OCID's Category 3 project is described later in this report.

Verification

Time-of-use meters were used to verify the peak load reduction, comparing the peak period electrical use of the 2003 season with that of the 2000 season.

Project Results

Summary Category	Results
Total Project Cost	$99,848.16
Total Grant Payment	$31,575
Actual kW Reduced	126.3
Grant Payment per kW Reduced	**$250**

City of Santa Rosa

Site

The City of Santa Rosa is located in northern California 30-40 miles north of San Francisco. The pump station that was modified supplies water for irrigation to a 250-acre dairy farm.

Project Description

The district proposed and designed a project that curtailed 46 kW of peak load. The application for this project was received on November 30, 2001. The project was started January 2001 and fully completed April 1, 2002. The City of Santa Rosa received the first 50% of the grant in June 14, 2002. Final verification was completed and the district received their final grant payment in November 25, 2003.

The peak load reduction was accomplished by retrofitting an existing pumping plant by installing variable frequency drives (VFD's) on 2-60 HP motors, which supply water to irrigation systems. A programmable logic controller (PLC) adjusts the speed of the motors so that only the water necessary for delivery is pumped. The new station configuration allows the system to be operated primarily during off-peak hours, resulting in lower peak energy consumption.

Verification

Time-of-use meters and the control package for the system were used to verify the peak load reduction, comparing the peak period electrical use of the 1997 peak period with that of the 2003 peak period.

Project Results

Summary Category	Results
Total Project Cost	$71,662
Total Grant Payment	$8,625
Actual kW Reduced	46
Grant Payment per kW Reduced	**$187.50**

Sutter Extension Water District

Site

Sutter Extension Water District (SEWD) is located in northern California near Yuba City.

Project Description

The district proposed and designed a project that curtailed 23 kW of peak load. The application for this project was received on November 1, 2001. The project was started November 2001 and fully completed April 2002. SEWD received the first 50% of the grant on June 1, 2002. Final verification showed that the project only curtailed 23 kW of the anticipated 66 kW therefore the district did not receive the final 50% of the contracted grant value.

The peak load reduction was accomplished by installing a variable frequency drive (VFD) on a 350 HP motor, which is one of three motors in the pumping station. A programmable logic controller (PLC) monitors the flow rate downstream of the pumps and adjusts the speed of the motor accordingly, so that only the water necessary for delivery is pumped, resulting in less spill and lower energy consumption. Soft-starts accompanied the VFD, to slowly ramp the motors up to speed, thereby reducing the in-rush current. This project also included the rewinding of the motors, a transformer to reduce the voltage, flow meters, and other necessary components.

Verification

Time-of-use meters and the control package for the system were used to verify the peak load reduction, comparing the peak period electrical use of the 2001 peak period with that of the 2002 peak period. The actual power data showed a peak load reduction of 23 kW from May-September, 43 kW less than anticipated. This is an example of the difficulty in anticipating peak load reduction with VFDs. The overall efficiency of the pumping plant was enhanced. Before the VFD was installed, the pumping plant would need 81.8 kWh to pump 1 acre-foot (AF). After the VFD was installed, the pumping plant only needed 61.6 kWh to pump 1 AF. This represents a total peak season (May – September) energy savings of 94,793 kWh. This savings is over every hour of every day that the pumping plant is operational, not only the peak period.

The justification for paying the first 50% of the grant was based on Category 2 – Option 2 rebate calculation based on kWh/AF improvement shown below. If this project was in Category 2, it would have qualified for $8,985. Therefore, the first 50% of the grant payment ($8,250) is justifiable.

$$\text{Rebate} = \$.1025 \times \left[1 - \frac{\text{Post } \frac{\text{kWh}}{\text{AF}}}{\text{Pre } \frac{\text{kWh}}{\text{AF}}} \right] \times (\text{4 month Hours}) \times \text{kW}$$

$$\text{Rebate} = \$.1025 \times \left[1 - \frac{61.6 \frac{\text{kWh}}{\text{AF}}}{81.8 \frac{\text{kWh}}{\text{AF}}} \right] \times (\text{1360 hours}) \times 261\text{kW} = \$8{,}985$$

Project Results

Summary Category	Results
Total Project Cost	$124,295.95
Total Grant Payment	$8,250
Actual kW Reduced	23
Grant Payment per kW Reduced	**$358.70**

Hills Valley Irrigation District

Site

Hills Valley Irrigation District (HVID) is located in the southern section of the Central San Joaquin Valley.

Project Description

The district proposed and designed a project that curtailed 20 kW of peak load. The application for this project was received on July 24, 2001. The project was started August 15, 2001 and fully completed October 31, 2001. HVID received the first 50% of the grant on August 7, 2002. Final verification was completed and the district received their final grant payment on July 29, 2004.

The peak load reduction was accomplished by installing a Variable Frequency Drive (VFD) on an existing 60 HP motor. The VFD will match the water supply with the downstream demand, reducing excess use of electricity.

Verification

Time-of-use meters and a chart recorder were used to verify the peak load reduction, comparing the peak period electrical use of the 2001 peak period with that of the 2002 and 2003 peak periods.

Project Results

Summary Category	Results
Total Project Cost	$20,825
Total Grant Payment	$4,800
Actual kW Reduced	20
Grant Payment per kW Reduced	**$240**

Kaweah River Power Authority

Site

Kaweah River Power Authority (KRPA) maintains and operates Terminus Dam Hydropower Plant at Lake Kaweah in Tulare County. Terminus Dam Hydropower Plant is owned by Tulare Irrigation District (TID) and Kaweah Delta Water Conservation District (KDWCD). Together, the two public agencies form the Kaweah River Power Authority (KRPA). The electricity generated at the power plant is sold to Southern California Edison (SCE).

The power generation through the power plant is a function of both lake elevation and release. Based on the turbine design/rating curves and operating experience, for every 100 cfs increase in reservoir releases, the corresponding increase in power generation is 1,000 to 1,300 KW up to a maximum turbine capacity of about 1,430 cfs. The summer releases out of the reservoir are on a "on demand" basis (i.e., to satisfy the irrigation daily water orders of TID's landowners and other water users on the Kaweah River system). Thus, the flow through the turbine will vary according to the cumulative irrigation demand and reservoir elevation.

Project Description

KRPA proposed and designed a project that increased peak load generation by 1.18 MW. The application for this project was received on March 13, 2003. The project was fully completed June 1, 2003. KRPA received the first 50% of the grant on July 2, 2003. Final verification was completed and the district received their final grant payment in November 2004.

KRPA increased the generation during the peak period by modifying the existing turbine at Terminus Dam to take advantage of the increased water level that will be made available through a USCOE dam enhancement project. Turbine modification was necessary to increase the maximum generation of the facility from 18.5 to 20.5 MW.

Verification

Utilizing generation records for 2004 was not an option for a realistic verification because of the unusually dry water year. Releases were significantly below normal. Instead, a model was used utilizing 2003 reservoir inflow data and estimated releases from Terminus Dam based on modified operations with the completed APLRP project. Details of the verification procedure and results can be found in **Appendix D**.

Project Results

Summary Category	Results
Total Project Cost	$583,768
Total Grant Payment	$293,066
Actual Peak kW Generated	1,180
Grant Payment per kW Generated	**$248.36**

Category 1b - Fuel Switching Rebate

Initially, many water agencies were interested in switching from electric motors to diesel motors for pumping. However, under the guidelines set forth in SB 5x, no grant funding could be provided for projects involving diesel. Because of air quality issues with diesel combustion engines, most water agencies in California are not allowed to use diesel engines for water pumping. Some agencies considered using propane or natural gas, but after analyzing the fuel cost variation and other factors involved with switching from electric motors to combustion engines, most agencies opted not to participate in this type of project.

Relatively new technology called microturbine generators were another option some agencies looked into. These relatively small turbine generators can run on a number of fuels, including propane, natural gas, and biogas. They generate electricity so that the existing electric equipment remains, but instead of using grid electricity, the equipment uses the electricity from the microturbines. The major limiting factor is cost. Microturbines cost between $1,000-$2,000 per kW. The APLRP rebate only covers $250/kW maximum.

The results of this program can be found in the table below.

Table 2. Category 1 Fuel Switching Rebate results.

	Projects that have been verified & TOTAL Grants Paid
Total Projects	**3**
Total Project Costs	**$768,223**
Total Grants	**$205,000**
Total kW Reduction	**820**
$/kW - Grants	**$250**

Category 2 - Pump Efficiency Testing and Pump Retrofit and Repair

Pump Testing

Table 3 below contains Category 2 pump test results. The table contains the number of applications received, the number of water agencies (districts) that participated, the grant funding, and the number of pump tests conducted. Applications were sent in by pump testing companies or water agencies that conducted their own tests. Generally, a group of tests was sent in with each application.

Table 3. Category 2 pump test results.

	Pump Testing Results
Applications	48
Districts Included	36
Grant Funding	**$215,474**
Number of Tests	**1,155**

Figure 4 shows the quantity of pump tests performed in each county participating in this category.

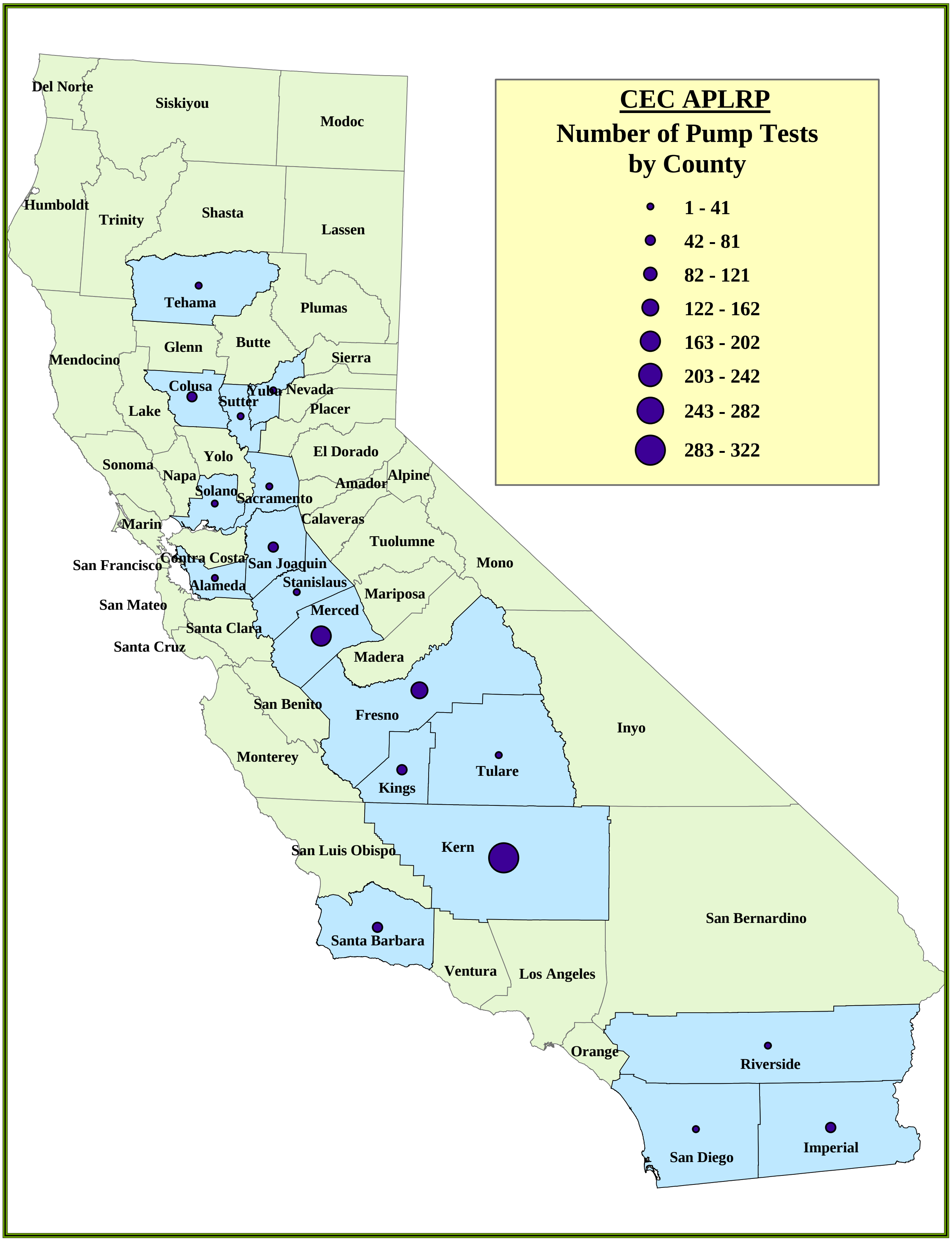

Figure 4. Illustration showing the quantity of pump tests by county.

Data compilation for the submitted pump efficiency tests resulted in a variety of charts and tables, thereby offering insight to the status of water agency pumping systems. A very small percentage of pumps tested did not qualify for the rebate. In some cases, the pump test company had to redo parts of the test to qualify, but for the most part pump testers followed the pump test requirements set forth by the program satisfactorily. The data for the tests that qualified for a rebate are illustrated throughout this section of the report. **Figure 5** represents the number of efficiency tests by pump size in kilowatts (kW).

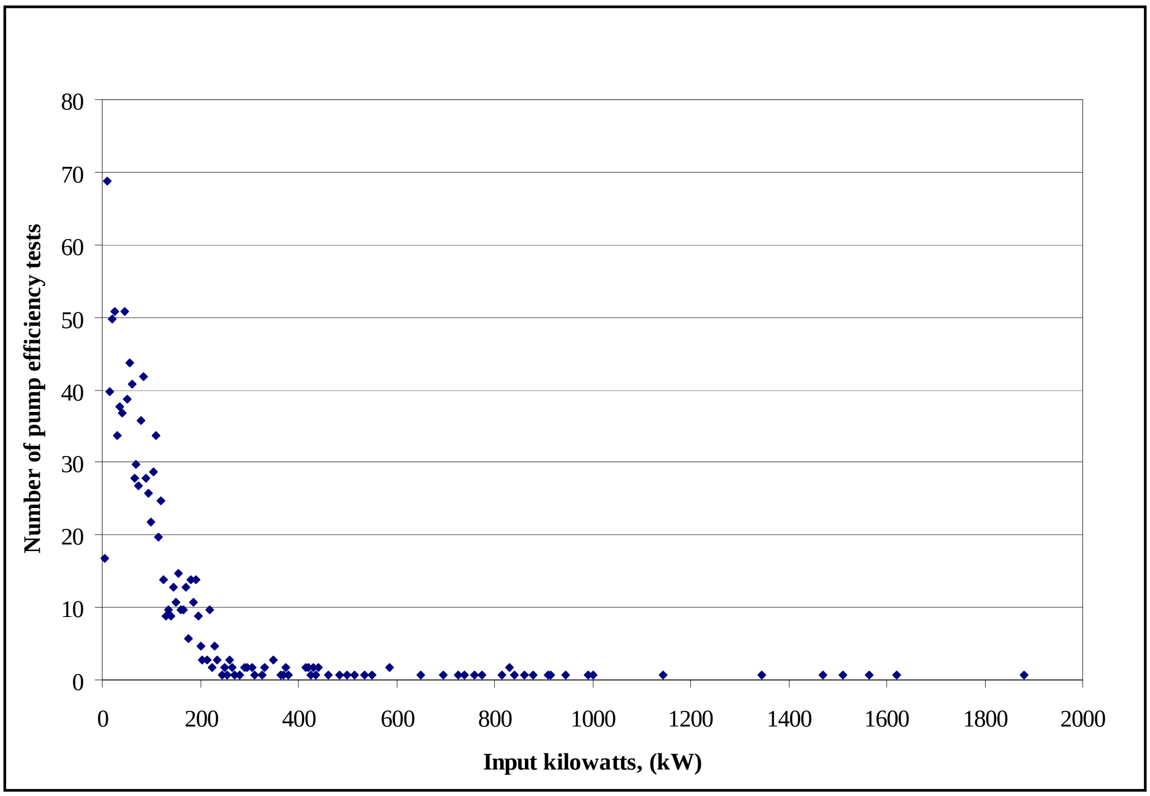

Figure 5. Number of pump efficiency tests per range of input kilowatts.

Figure 5 shows that most of the pumps tested were between 10 and 200 kW. The majority of pumps used by agricultural water agencies throughout California are also in this range of input kW.

Using the basic relationship between input kilowatts and water kilowatts, the overall pumping plant efficiency can be calculated per pump. **Figure 6** displays the number of pump efficiency tests reviewed in each incremental range (increments of 5%) of overall pumping plant efficiency (OPPE).

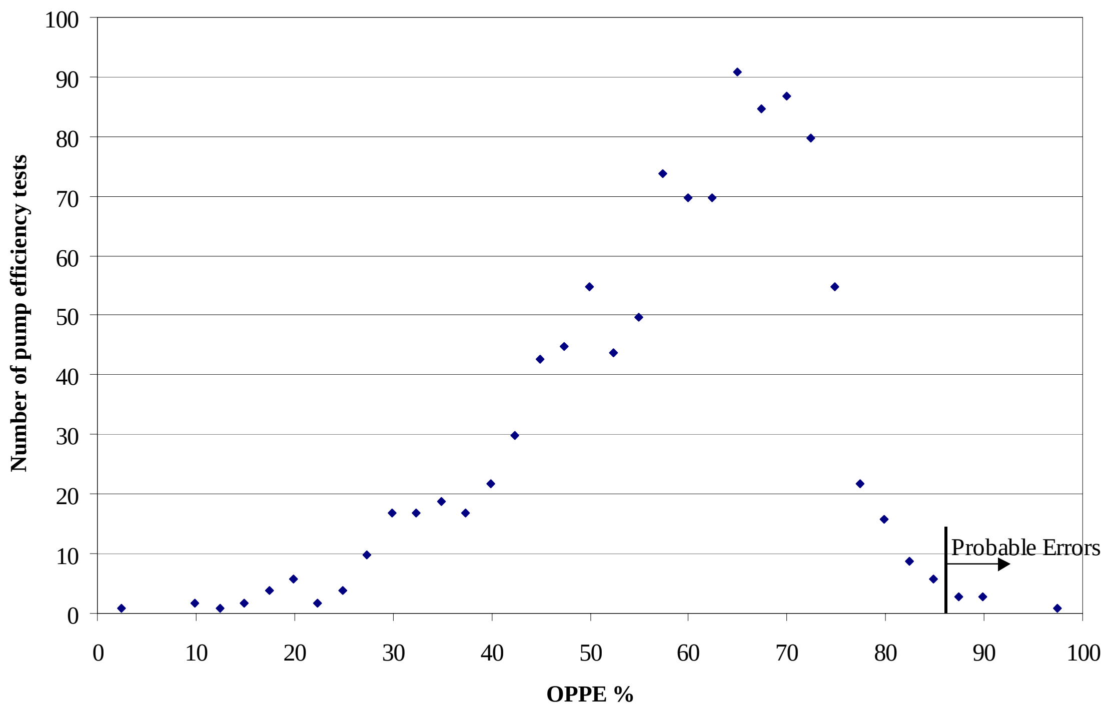

Figure 6. Number of pump efficiency tests per range of OPPE.

Figure 6 above illustrates that the majority of reviewed pump efficiency tests have an efficiency ranging from approximately 50% to 75%. However, the graph depicts outliers as well. Of particular interest are those pumps to the left of 85% OPPE. As mentioned earlier, it is improbable that a pumping plant would have an OPPE greater than 85%; therefore, it is most likely that an error occurred during the test.

The potential energy savings are illustrated in **Figure 7**. The savings are representative of those pumps whose overall pumping plant efficiency was determined to be less than 75%. Pumps whose efficiency was greater than 75% were removed from the chart data since the effect would be a negative potential kW savings (reduction of efficiency).

Using the methodology expressed in **Appendix C**, and summing the potential kilowatt (kW) savings for each pump tested with an OPPE below 75%, 17,230 kW of energy demand could be reduced by repairing or retrofitting pumps to raise OPPE to a reasonable 75%.

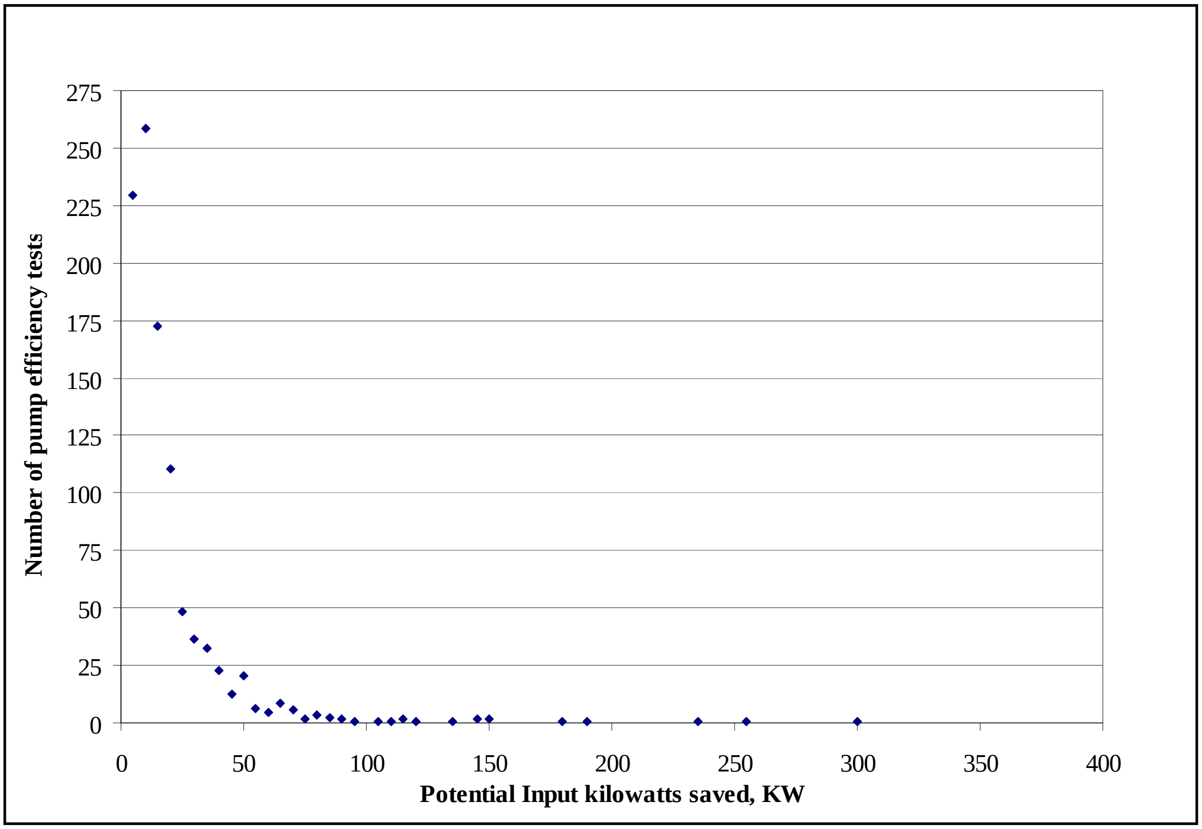

Figure 7. Potential energy savings resulting from OPPE increase.

Average OPPE for each water agency was calculated by averaging the efficiency tests of the pumps within that district, as illustrated in **Figure 8**. Abbreviated agency IDs, which are used in **Figure 8**, are listed in **Table 4**, corresponding to the full name of the district.

Table 4. Water agency identification.

Water Agency ID	Water Agency Name
BWSD	BELRIDGE W.S.D.
BMWD	BERRENDA MESA W.D.
BVWSD	BUENA VISTA W.S.D.
CWD	CAWELO W.D.
CCID	CENTRAL CALIFORNIA I.D.
DEID	DELANO-EARLIMART I.D
IID	IMPERIAL I.D.
JID	JAMES I.D.
KCWA	KERN COUNTY W.A. IMPROV.DIST. #4
KTWD	KERN-TULARE W.D.
LHWD	LOST HILLS W.D.
MID	MERCED I.D.
Pacheco WD	PACHECO W.D.
RD 2039	RECLAMATION DISTRICT NO.2039
PID	PATTERSON I.D.
RD 2058	RECLAMATION DISTRICT NO.2058
RD 3	RECLAMATION DISTRICT NO.3
RD 684	RECLAMATION DISTRICT NO.684
SYRWCD	SANTA YNEZ RIVER W.C.D.
WWD	WESTSIDE W.D.
WRMWSD	WHEELER RIDGE-MARICOPA W.S.D.
PNWD	PANOCHE W.D.
RD 108	RECLAMATION DISTRICT NO. 108
SSJID	SOUTH SAN JOAQUIN I.D.
RD 548	RECLAMATION DISTRICT NO. 548
AWD	ANGIOLA WD
CNWD	CORNING WD
AID	ALPAUGH ID
RD 2033	RECLAMATION DISTRICT 2033
TID	TRANQUILLITY ID
CID	CORCORAN ID
KWBA	KERN WATER BANK AUTHORITY
TBID	TERRA BELLA ID
RD 2068	RECLAMATION DISTRICT 2068
SID	SOLANO IRRIGATION DISTRICT
EMWD	EASTERN MUNICIPAL WATER DISTRICT
BVID	BROWNS VALLEY IRRIGATION DISTRICT
SDCWA	SAN DIEGO COUNTY W.A.
RD 2029	RECLAMATION DISTRICT 2029
NCMWC	NATOMAS CENTRAL MUTUAL W.C.
RD 2065	RECLAMATION DISTRICT 2065
RD 756	RECLAMATION DISTRICT 756
SEWD	SUTTER EXTENSION W.D.
CCWD	COLUSA COUNTY W.D.

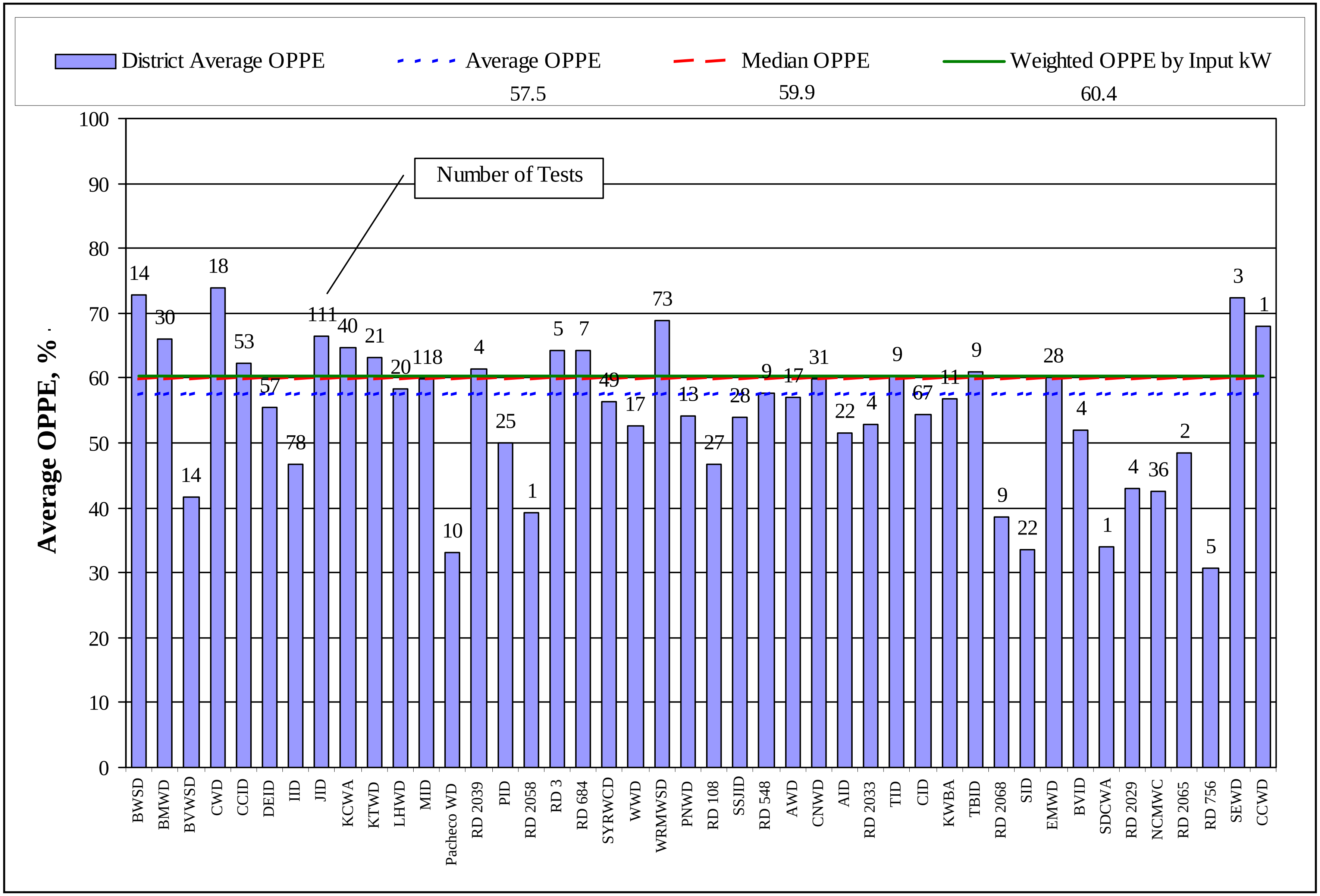

Figure 8. Overall pumping plant efficiency by water agency.

According to the guidelines, the pump efficiency tests in this report had to be performed at minimum distances from various obstructions within the pipe (**Appendix B**). **Table 5** lists the type of fitting that may exist in a pipe, corresponding to a fitting ID, both of which correlate to **Figure 9**. **Figure 9** illustrates the percentage of pump tests that were conducted near a particular fitting in the pipe.

Table 5. Fitting identification.

Fitting ID	Valve or Fitting
a	Upstream of an elbow
b	Downstream of an elbow
c	Swing check valve (the flap on this type of check valve swings completely out of the flow path)
d	Regular check valve
e*	Any partly closed valve, or Pump control valve, or Globe valve
f*	Open gate valve
g*	Open butterfly valve
h	Pump discharge
i	Other (i.e. Propeller Meter, Open Channel, etc.)

*Valve or fitting types e, f, and g comprised of less than a percentage point, and therefore do not appear on the graph.

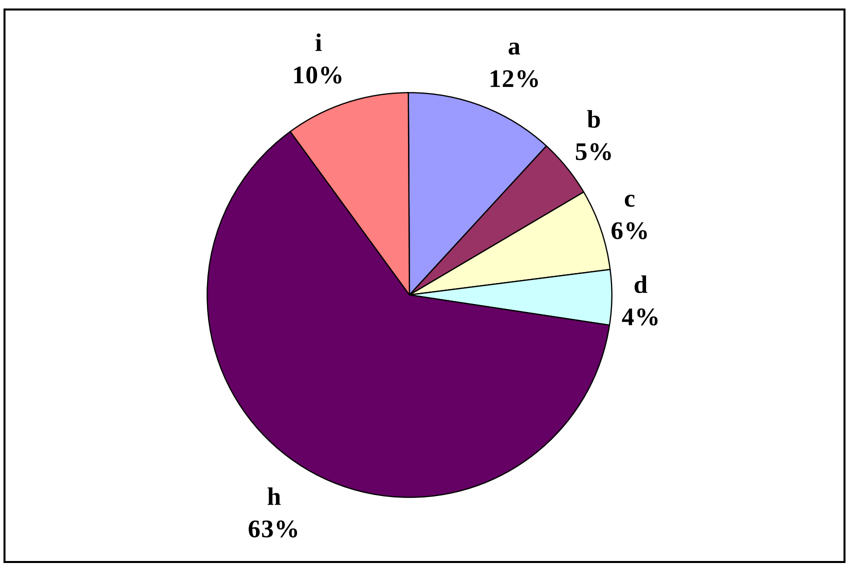

Figure 9. Percentage of pumps tested near a particular fitting.

Figure 9 indicates that the majority of pump efficiency tests were completed near the discharge of the pump.

Table 6. The number of single and double transect pump efficiency tests for each measurement device. (27 tests were conducted before this information was required)

	Transects	
Flow Measurement Device	**Single**	**Double**
Collins Tube or similar	283	3
Propeller Meter	206	0
Ultrasonic	416	180
Other*	40	0
Total	**945**	**183**
Total Number of Tests	**1,128**	

* Includes open channel flow measurement devices or the customer's existing flow measurement devices. All devices in this category were pre-approved by ITRC.

Overwhelmingly, the majority of pump efficiency test results were obtained from single transect measurements. Pressure differential (Collins tube or similar) and ultrasonic flow measurement devices were the major measurement devices used.

Pump Retrofit/Repair

Pump retrofit/repair projects utilized the bulk of the Category 2 grant funding. ITRC estimates that over 21 million kWh have been and will continue to be saved on an annual basis through the ITRC-administered pump retrofit/repair program. **Table 7** provides the number of pump repairs for each option and the grant funding for pump retrofit/repair.

Table 7. Pump retrofit/repair results.

Payment Option	Number of Projects	Estimated Annual kWh Savings	Grant Funding
Option 1	**3**	**436,663**	**$76,097**
Option 2	**8**	**390,457**	**$32,208**
Option 3	**216**	**11,077,012**	**$1,250,484**
65% of Project Cost	**72**	**9,106,829**	**$781,738**
Total	**299**	**21,010,962**	**$2,140,527**

Total Districts Participating	**35**

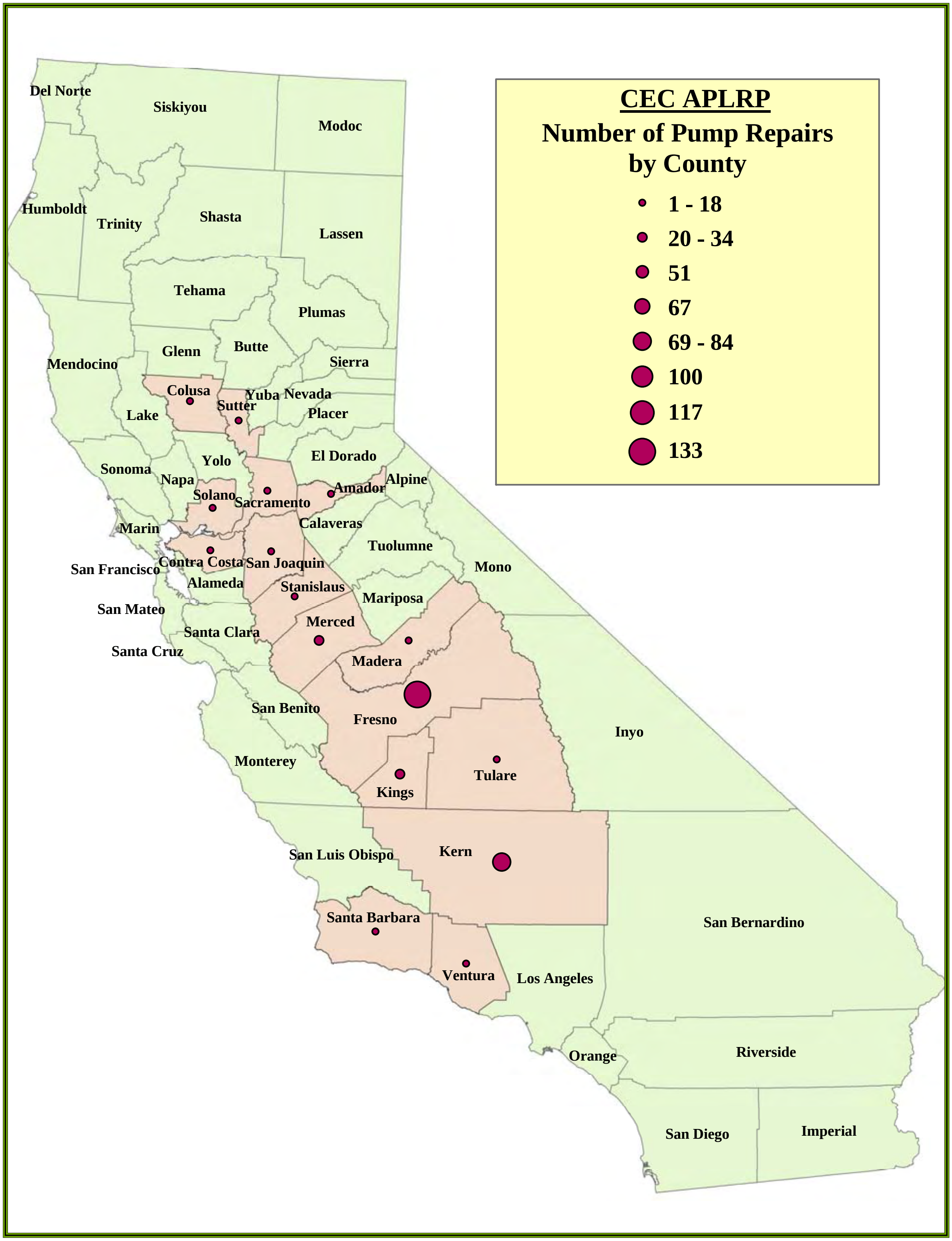

Figure 10. Illustration showing the quantity of pump repairs by county.

The actual kWh savings data obtained from each project was limited by which grant payment option was chosen to calculate the rebate. Option 1 required pre- and post-retrofit/repair measurement of input kW. Option 2 required pre- and post-retrofit/repair pump tests and June-September hours of operation. The benefits of using either of these two options were that they generally had a higher rebate value for the same type of repair as compared to Option 3, and that almost any retrofit/repair to the pumping plant would qualify. The rebate calculated for Options 1 and 2 was based on the actual peak kW reduction due to the retrofit/repair.

Option 3 required only the submission of annual kilowatt-hours of operation and the replacement or repair of the impellers or bowls. The benefit to the water agency using Option 3 was that a post-retrofit/repair pump test was not required; on the other hand, replacing or repairing the pump impeller or bowls was required. Since the post-repair test was not required for Option 3, hard data on the pump efficiency improvement for most repairs was not available. Therefore, the rebate for Option 3 was based on an assumed 20% reduction in energy (kWh) usage. Although in some Option 3 projects the savings may have been more then 20% and in others it may have been less, if the water agency replaced or repaired the pump impellers, the assumption was that savings should be significant.

Table 8 compares pre- and post-repair overall pumping plant efficiencies (OPPE) for six Option 2 projects. This shows a ballpark range of OPPE improvements with pump repairs. However, it is important to note that Option 2 did not require impeller or bowl repair or replacement, so OPPE improvement for Option 3 repairs is likely significantly higher.

Table 8. Option 2 overall pumping plant efficiency improvement for six pump repair projects.

Option 2 Sample	**Pre-Repair OPPE%**	**Post-Repair OPPE%**	**Change OPPE%**
River Plant #2	46.0	61.8	15.8
Station 1, Pump 7	46.0	66.3	20.3
Camp 8	53.5	70.6	17.1
Lateral 5, Pump 3	48.0	68.0	20.0
Lateral 5, Pump 4	43.0	64.0	21.0
Lateral 7, Pump 4	44.0	59.0	15.0
		Average	**18.2**

The pump efficiency testing and retrofit/repair category for water agencies should result in significant annual energy savings. Blaine Hanson of Univ. of California extension has documented that typical agricultural pump repairs often do not save power. This is because farmers are often able to pump more water with rebuilt pumps, but they do not reduce the hours of pumping after a pump is rebuilt – they just pump more volume per year. However, water agency pumps are not operated the same as on-farm pumps. With water agencies, there is generally a specified volume of water that must be pumped per year. Therefore, improving pumping plant efficiency truly saves energy in irrigation districts.

Estimating annual energy savings from the pump retrofit/repair category was different for each of the three grant calculation options:

Option 1.

$$\boxed{kWhsavings = (pre - repairkW - post - repairkW) \times (June - September \quad Hours \quad of \quad Operation)}$$

Option 2.

$$\boxed{kWhsavings = \left(\frac{pre - repairkWh}{AF} - \frac{post - repairkWh}{AF} \right) \times \left(June - September \quad AF \quad pumped \right)}$$

Where

June – September AF pumped is calculated using pre-repair pumping plant flow rate and June – September hours of operation.

Option 3.

$$\boxed{kWhsavings = \left(20\% \times Annual \quad kWh \right)}$$

Using the equations above for Options 1 and 2 actually results in a slight underestimation of annual energy (kWh) savings because pumping plants often operate during the Spring and Fall, in addition to the June – September hours of operation, but only data for June-Sept. was requested on the applications. However, since the peak operation of most agricultural pumps in California is June-September, the amount of underestimation is not likely to be significant.

Table 9 lists the types of work completed during a pump retrofit/repair operation. **Figure 11** shows the number of pump tests that were completed for each type of work.

Table 9. Work completed (key for Figure 11)

Number	Type of work completed
1	Motor replacement
2	Motor rewind
3	Bearing/spider replacement
4	Packing replacement
5	Impeller repair
6	Impeller trimming
7	Impeller replacement
8	Bowl/volute repair
9	Bowl/volute replacement
10	Adding stage(s) (if a turbine)
11	Removing stage(s)
12	Increasing the column pipe diameter
13	Modification of the immediate pump discharge piping or valving to reduce pressure requirements
14	Well clean/modification to reduce drawdown
15	Final pump test
16	Other

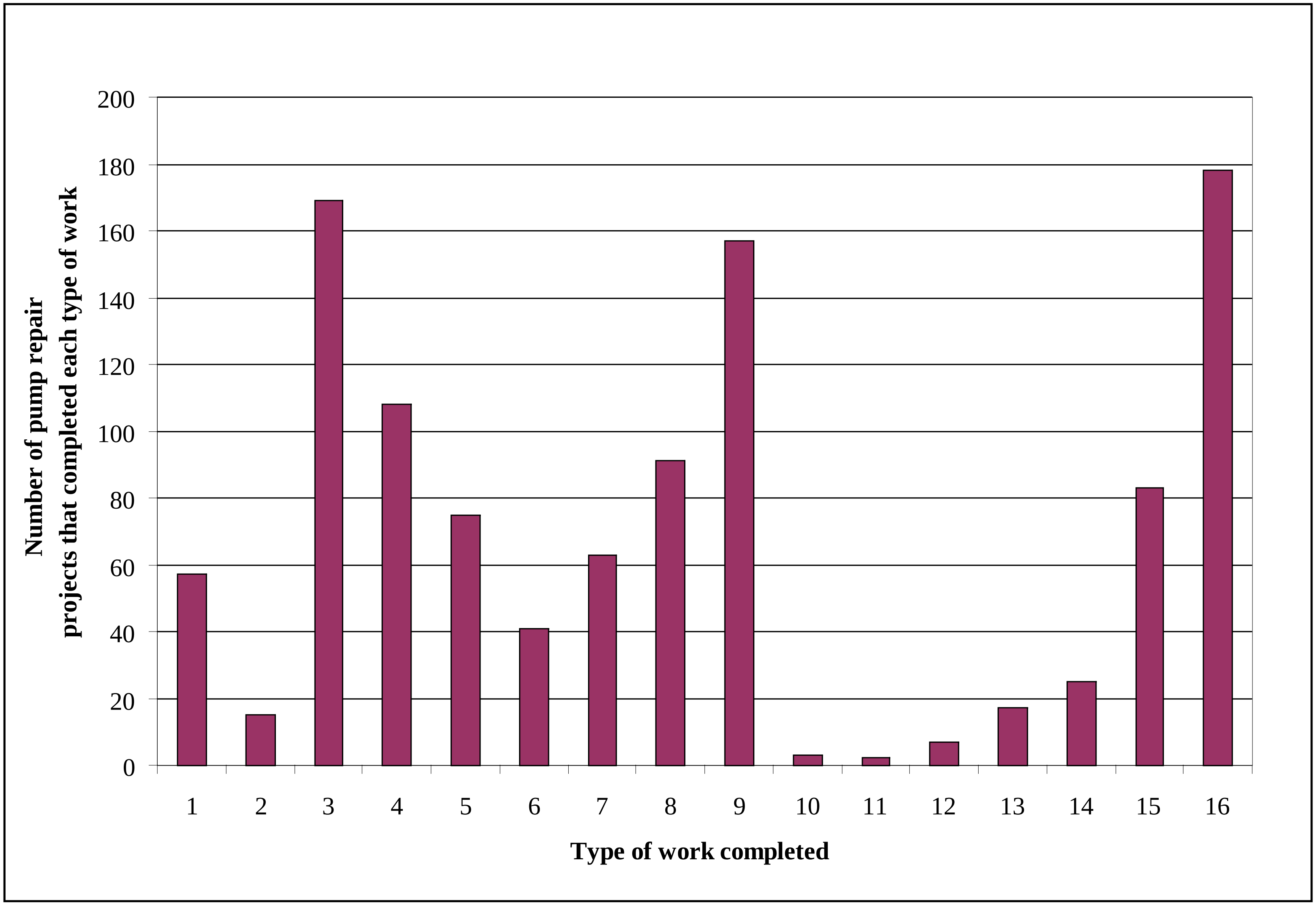

Figure 11. The typical work completed during the pump repair/retrofit.
For each pump retrofit/repair project there were multiple types of work done on the pumping station.

Figure 11 indicates that a large number of pump retrofit/repair projects involved replacing packing and bearings/spiders. Bowl and impeller replacement or repair (5-9) was also significant. This is consistent with the fact that a majority of the pump retrofit/repairs used Option 3 as the grant calculation method.

Pump retrofit/repair projects have the greatest amount of true energy (kWh) savings in this program since the projects actually reduce energy demand, rather than just shifting the energy demand to either other time periods or other fuel types as projects in other categories do.

Category 3 - Advanced Metering/Telemetry

This category can be split into two sections – ISO and Non-ISO projects.

Category 3a: ISO Projects

The California Independent Systems Operators (ISO) is responsible for providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. During the energy crisis the ISO implemented a Demand Relief Program (DRP) providing monetary incentives for large demand users on the energy grid to voluntarily remove demand from the energy grid when called upon to do so by the ISO, to help prevent a potential blackout from occurring. In turn, these participants would receive a payment from the ISO based on the amount of demand removed from the utility grid. The participants also received limited funding just for participating in the DRP whether they were called to reduce load or not.

The CEC Agricultural Peak Load Reduction Program (APLRP) was not directly involved with the California ISO Demand Relief Program. However, grant funding was made available through the APLRP to assist water agencies with the initial capital investment needed to participate in the DRP. The grants were limited to the cost for advanced metering and telemetry equipment and installation of that equipment.

The largest number of Category 3 projects involved installing advanced metering to participate in the 2001 California ISO Demand Relief Program. These projects are identical in description and verification. Therefore, each project will not be discussed independently. The process involved for water agencies to participate in the APLRP for ISO projects is as follows:

1. The water agency contacted the ISO or a subcontractor such as Ancillary Services Coalition to begin a contract process to participate in the DRP.
2. The water agency then applied to participate in the CEC Agricultural Peak Load Reduction Program (APLRP) for Water Agencies through ITRC. Once the project

was approved by ITRC and CEC, the water agency had interval meters and cellular modems installed on the equipment that will participate in the DRP.

3. Once this was complete, the contract with the ISO was finalized. The final signed contract between the water agency and the ISO and the invoices showing that the equipment was installed were the only verification necessary to receive grant funding from the CEC APLRP.

The following is a list of districts participating in the Category 3a ISO project showing the load that was contracted through the DRP.

District Name	Participating KW
City of Bakersfield	1,737
Natomas Central Mutual Water District	1,270
Solano Irrigation District	1,000
Westlands Water District	17,703
Westlands Water District -- Woolf Telemetry	534
Westlands Water District -- Vasto Valle Telemetry	725

Table 10 summarizes the results from Category 3a ISO projects. The total peak kW reduction was the kW the water agency signed up for under the ISO program. Generally, the costs for these projects were relatively low compared to Category 1 and 2 projects. The equipment for these projects was relatively inexpensive compared to reservoir construction costs or costs for labor intensive pump retrofit/repairs.

Table 10. CEC APLRP Category 3a ISO Demand Relief Projects Summary.

	Projects that have been verified & TOTAL Grants Paid
Total Projects	**6**
Total Project Costs	**$489,539**
Total Grants	**$318,200**
Total kW Participating	**22,969**
$/kW - Grants	$14
$/kW - Project Cost	$21

Category 3b: Non-ISO Projects

Other water agencies participated in the Category 3 Advanced Metering/Telemetry program to reduce peak load and were not involved with the ISO Demand Relief Program. Generally, these agencies installed telemetry and advanced metering to assist in demand curtailment management and operation as part of a larger Category 1 project. For example, North Kern Water Storage District (NKWSD) repaired well casings and built reservoirs in their first project. The second project also involved replacing or repairing well casings, as well as installing a telemetry system on reservoirs to monitor water levels. Both of these projects for NKWSD are summarized in the Category 1 section of this report.

Table 11. CEC APLRP Category 3b Non-ISO Projects Summary.

	Projects that have been verified & TOTAL Grants Paid
Total Projects	**2**
Total Project Costs	**$1,104,308**
Total Grants	**$581,167**
Total kW Reduction	**2,423**
$/kW - Grants	$240
$/kW - Project Cost	$456

Two projects are included in this section as primarily Category 3b projects: the Tulare Irrigation District (TID) project and Orange Cove Irrigation District's (OCID) first project.

The TID project was incorporated in both Category 1 and Category 3. Most of the project fell into Category 3; therefore, it will be summarized in this section of the report.

OCID has a delivery system and reservoirs in place with the capacity to supply a majority of water users, on certain sections of their distribution system, during the off-peak period. However, the district was lacking telemetry (Supervisory Control and Data Acquisition System (SCADA)) on parts of their system. In order to curtail a majority of their peak load, it was necessary for the district to automate pumping stations and remotely monitor reservoir water levels.

Tulare Irrigation District and Kaweah River Power Authority

Site

Tulare Irrigation District (TID) is located on the east side of the Central San Joaquin Valley just south of Visalia, CA. The district receives water from Lake Kaweah through Terminus Dam as well as from the Friant-Kern Canal. TID is the single largest partner in Kaweah River Power Authority (KRPA), which operates Terminus Dam and regulates the discharge from Lake Kaweah.

Project Description

TID and KRPA proposed and designed a project that increased the generated peak load from Terminus Dam by 2,280 kW. The application for this project was received on February 24, 2003. The project was started March 2003 and fully completed July 2004. TID received the first 50% of the grant in October 2004. Final verification was completed and the district received their final grant payment in November 2004.

Several structural, control, and SCADA investments were necessary to facilitate implementation of a California Energy Commission (CEC) grant proposal by the district. The proposal was to fluctuate TID releases from Terminus Dam during the day so that the Terminus Dam generating turbine would be at maximum capacity during the peak period. During the off peak period the releases would be reduced so that TID would receive the required daily volume of irrigation water. During the excess releases during the peak period are stored in regulating reservoirs within TID boundaries so they could be used during the off peak period when flows from Terminus are reduced.

A second function of the project was to selectively choose the water sources tapped by the district in order to utilize the maximum amount of water from Kaweah Reservoir during hours of peak electrical demand. By selectively using the water from Kaweah Reservoir, the maximum output of the hydroelectric generating plant at the dam will coincide with peak electrical demand. The other district surface irrigation water source is the Friant-Kern Canal. This second function is not presently available to TID because the Friant-Kern Canal currently does not have the flexibility to make large flow rate changes multiple times during the day. In the future, the district expects to be able to utilize this function of the project, which would maintain the water level in Lake Kaweah longer into the peak season further increasing the peak generating capacity.

In general, the system improvements are used to facilitate the time dependent use of water by accomplishing the following:

- Provide a method for the Kaweah-Delta WCD (KDWCD) system operators to manage large fluctuations in flow on the Kaweah River, without interfering with the operation of the irrigation districts and canal turnouts.
- Provide a method for TID to control and monitor the variable flows as they enter the district boundaries and pass to the two key reservoirs.
- Control and monitor the status of two key reservoirs in the district.

Verification

Utilizing generation records for 2004 was not an option for a realistic verification because of the unusually dry water year. Instead, a model was used utilizing 2003 reservoir inflow data and estimated releases from Terminus Dam based on modified operations with the completed APLRP project. Details of the verification procedure and results can be found in **Appendix D**.

Project Results

Summary Category	Results
Total Project Cost	$1,047,852.16
Total Grant Payment	$512,125
Actual kW Reduced	2,280
Grant Payment per kW Reduced	**$224.62**

Orange Cove Irrigation District – Category 3 Project

Site

Orange Cove Irrigation District (OCID) is located on the east side of the Central San Joaquin Valley southeast of Fresno. The district receives water from the Friant-Kern Canal.

Project Description

The district proposed and designed a project that curtailed 637 kW of peak load. The application for this project was received on June 29, 2001. The project was started in September 2001 and fully completed in October 2001. OCID received the first 50% of the grant in December 2001. Final verification was completed and the district received their final grant payment in December 2002.

To reduce peak load, remote system monitoring, measurement and control components were installed for sections of the water distribution system not currently equipped. The equipment provided the agency with the capability to monitor load, flow, and pumping efficiency in real time. In addition, Systems 3A & 8 were controlled to respond to critical water levels in their respective reservoirs. Critical alarms were also installed as part of the telemetry project. OCID reprogrammed the pump activation process so that the most efficient pumps would run the majority of the operational hours and the least efficient pumps would run the least.

The agency also instituted a landowner load reduction program, whereby individual growers signed up with OCID to commit to a kW reduction during the peak period. In return, the district reduced the price of water for the growers.

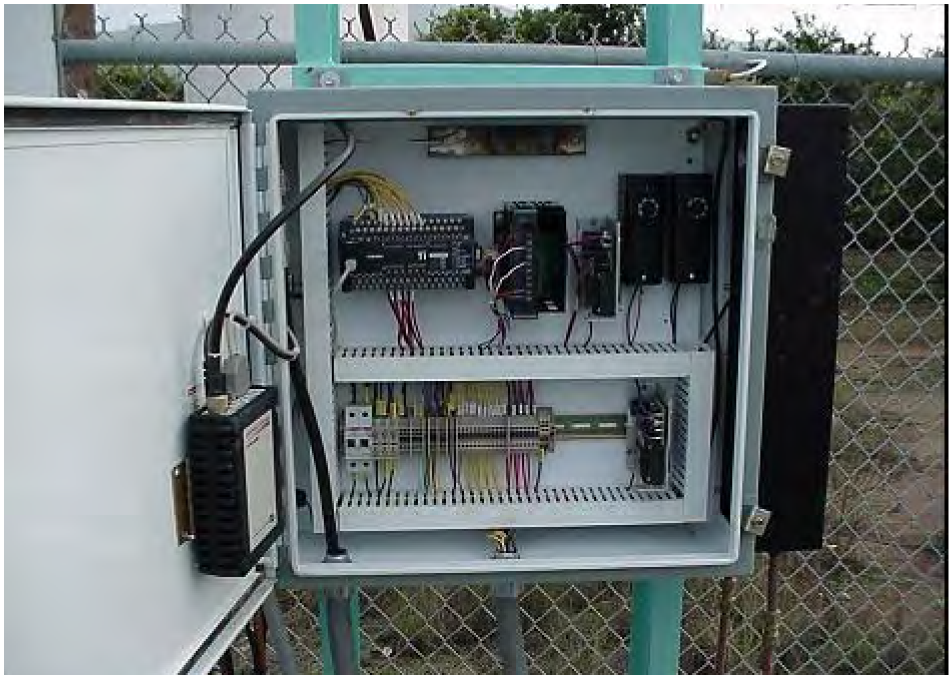

Figure 12. SCADA panel in Orange Cove Irrigation District used to monitor and control a pump station.

Verification

Time-of-use meters were used to verify the peak load reduction, comparing the peak period electrical use of the 2002 season with that of the 2000 season.

Project Results

Summary Category	Results
Total Project Cost	$283,485
Total Grant Payment	$180,000
Actual kW Reduced	637
Grant Payment per kW Reduced	**$282.6**

Initially, OCID had planned to have the project completed by September 31, 2001. This qualified them for $300/kW curtailed grant. However, because of the tragedies of September 11, 2001, some of the equipment the district needed could not be delivered and the district was not able to complete the project until October 17, 2001. For this unforeseen reason the district was given an extension to the $300/kW deadline.

DISCUSSION

The California Energy Commission's Agricultural Peak Load Reduction Program was launched quickly and has resulted in major reductions in peak electrical load consumption by irrigation districts. The actual load reduction exceeded initial expectations. However, there was less dollar demand than expected. The lower-than-anticipated participation was probably due to following factors:

1. The short lead time for the program was unrealistic for many water agencies. Some agencies have projects with considerable potential for load shifting, but the projects would require construction permits, decisions by the district Boards of Directors, design, etc.
2. The 65% cost sharing is substantial, but so is the remaining 35% cost sharing. The 35% is more than some districts can afford, even if the projects have a 3- or 5-year payback. Prices for many agricultural commodities are at record or near-record lows. Farmers and districts often only invest in projects with immediate or one-year paybacks.
3. Many potential projects had a high capital cost and a relatively low load curtailment. The grant limit was $250/kW and only covered potentially 10-30% of the cost sharing.
4. The Category 1 projects often required innovative solutions, and for some water agencies the innovations could not be conceptualized or appreciated.
5. Some water agencies that could have participated receive inexpensive power from the Western Area Power Administration (WAPA), so there was little apparent economic incentive to participate.

The following items were also noted:

1. Agricultural water agencies that participated in Category 1 projects were quite enthusiastic. The electricity bills for these districts were typically substantial. This program provided a relatively inexpensive path to achieving long-term savings through reduced power rates due to reduced peak hour electricity use.

2. ITRC had anticipated that districts would be able to organize farmers along pipeline or canal laterals to shut off their pumps during peak hours. This would result in removing both water agency and farmer pumps from the peak demand. It has high potential in areas with pumped pipeline laterals serving drip systems. However, this proved to be too difficult for most districts to organize within the program's time frame without increasing staff.

3. When examining the water agencies that participated in Category 1, one major consistency exists. These agencies had excess capacity in their distribution systems, which allowed them to operate during the off-peak. Two prime examples are Orange Cove Irrigation District and North Kern Water Storage District. The extra capacity allowed the districts to move water to reservoirs and users in an 18-hour period instead of 24 hours with "minor" modifications (i.e., installing reservoirs and telemetry, rather than increasing pipeline or canal capacity and expanding pump stations throughout the district). Where minor modifications could be completed, water agencies could curtail a large amount of load while keeping their costs relatively low, qualifying them to receive the entire 65% cost sharing.

4. For Category 2, the new pump testing requirements have helped to improve the quality of future pump testing programs. Prior to this program, pump testers had little or no external quality control constraints. Most electric utilities provided regular pump testing free of charge. Since electric utilities began having financial problems, many of these programs were cut. As a result, many pumps throughout California have not been tested since then. This program provided the incentive for many water agencies to have these pumps tested and provided enough incentive to the pump tester to test them well.

5. The pump retrofit/repair program started slower than Categories 1, 3, and the pump testing program. The factors that caused this are probably:
    a. Water agencies were waiting for pump tests to be completed.
    b. Pumps must be taken off-line to retrofit/repair. Generally, this can only be completed during the off-season (October-March throughout most of California).

> By early fall 2001 the applications received for the pump retrofit/repair program increased dramatically. Even though most projects only had grant funding ranging between $1,000-$20,000, the total funding provided through this program was comparable with funding provided through Category 1.

The main objective of the Agricultural Peak Load Reduction Program was to reduce the peak load demand throughout the state of California. Water agencies throughout California achieved this objective by reducing more demand than anticipated, with lower than expected funding.

However, if this program were to be extended or renewed, it would difficult to ascertain the demand for funding for Category 1 projects with the APLRP as it now stands. ITRC has heavily promoted this program to water agencies and the major limiting factor for many water agencies is money. Of course, some potential projects could not be implemented within the timeframe of the program, but for many more, the $250/kW load reduction was not enough to make the projects feasible in the eyes of the water agency.

APPENDIX A

PROGRAM DESCRIPTION SENT TO WATER AGENCIES

APPENDIX B

APPLICATIONS

APPENDIX C

EQUATIONS FOR OBTAINING POTENTIAL KILOWATT SAVINGS FROM PUMP TESTING

Equations for Obtaining Potential KiloWatt Savings from Pump Testing

Potential kilowatt (kW) savings were estimated based on a reasonable attainable overall pumping plant efficiency (OPPE) assuming:

d. Impeller efficiency (E_I) of 82%
e. Motor efficiency (E_M) of 94%
f. Miscellaneous component efficiency (E_O) of 98%.

$$\boxed{OPPE = E_I \times E_M \times E_O \times 100} \tag{1}$$

$$\boxed{OPPE = 0.82 \times 0.94 \times 0.98 \times 100 \cong 75\%} \tag{2}$$

Having established a reasonable attainable efficiency, to calculate the potential kW savings, the basic relationship of efficiency applies for current (old) data and potential (new) data:

$$\boxed{\text{Input kW}_{old} = \frac{\text{Output kW}_{old}}{\text{Efficiency}_{old}}} \tag{3}$$

$$\boxed{\text{Input kW}_{new} = \frac{\text{Output kW}_{new}}{\text{Efficiency}_{new}}} \tag{4}$$

Using equations 3 and 4 to establish a relationship between current input energy and potential input energy, a ratio evolves:

$$\boxed{\text{Input kW}_{new} = \left[\frac{\text{Efficiency}_{old}}{\text{Efficiency}_{new}}\right] \times \text{Input kW}_{old}} \tag{5}$$

Equation 5 enabled the calculation of potential energy for each pump and therefore, determined the potential energy savings for the pumps tested.

APPENDIX D

TULARE ID VERIFICATION MEMO - EXAMPLE

IRRIGATION TRAINING AND RESEARCH CENTER
California Polytechnic State University
San Luis Obispo, California 93407
Tel: (805) 756-2434 Fax: (805) 756-2433 www.itrc.org

TECHNICAL MEMORANDUM

Date: September 9, 2004

To: J. Paul Hendrix
Tulare Irrigation District
1350 West San Joaquin Ave.
Tulare, CA 93274
(559) 686-3425

Jim Stadler
Kaweah River Power Authority
2975 N. Farmersville Blvd.
Farmersville, CA 93223
(559) 747-5601

From: Dan Howes and Dr. Charles Burt, ITRC

Subject: Tulare ID and KRPA CEC Grant Verification (2 Projects)

Executive Summary

Under the anticipated, revised release schedule from Terminus Dam the following results will be obtained.

Description	Average Peak MW Credited to each APLRP Project	Average Peak MW Needed for Full Grant Payment
Baseline = 11.885 MW		
TID SCADA Project (14.169 MW – 11.885 MW)	2.28	2.00
KRPA Turbine Enhancement Project (15.352 MW – 14.169 MW)	1.18	1.17
Total Increase in Peak Load Generation from APLRP Projects	**3.47**	3.17

In addition, there will be a substantial decrease in on-farm peak pumping from the groundwater in September, due to the new dam release schedule that will extend the availability of surface water. That decrease in peak pumping is estimated at about 8.24 MW during late August-September, which averages to **2.04 MW** over the complete period of June-Sept.

Anticipated average peak load reduction/generation = **5.51 MW**

Verification Description

This memo summarizes the results of the verification process for two CEC Agricultural Peak Load Reduction Program (APLRP) projects. The tasks for both projects were coordinated by the Kaweah River Power Authority (KRPA). The two projects are described as follows:

a. Tulare Irrigation District (TID). The TID project involved the addition of a Supervisory Control and Data Acquisition (SCADA) system and new hardware, as well as modifications in operation to reserve Lake Kaweah storage for release through Terminus Dam during the peak season (June – September). This project will be referred to as the "**TID SCADA project".**

b. Kaweah River Power Authority (KRPA). The KRPA project included a generator turbine enhancement. This enhancement was completed to utilize additional head created by raising the spillway on Terminus Dam (completed by the United States Army Corp of Engineers). This project will be referred to as the "**turbine enhancement project**."

Since both projects affect the power generated at Terminus Dam and since TID is the largest user of irrigation water from Lake Kaweah, this verification procedure incorporates both projects simultaneously.

In order for both projects to receive the full grant funding an additional **3.17 MW** must be generated during peak hours (noon-6 pm, M-F) on average from June 1st through September 31st. A relatively simple model was created by ITRC using current turbine generation and area capacity charts provided by KRPA. Once verified for accuracy, this model was used to simulate how the generating system would react under conditions of a typical year with modified dam releases (simulation development and verification of accuracy are described in **Attachment D-1**).

Utilizing generation records for 2004 was not an option for a realistic verification because of the unusually dry water year. The reservoir inflow for the 2004 water year (October 1, 2003 – September 31, 2004) as of the date of this report was 235,600 acre-feet (AF), compared to the average inflow for water years 1990-2003 of approximately 428,300 AF. Water year 2003 was used for the simulation because inflow to Lake Kaweah during 2003 was approximately 425,140 AF, much closer to the 14-year average.

This memo discusses peak load generation under the following scenarios, which were run using the model created by ITRC:

1. Actual 2003 operation
2. Increased lake storage only
3. The turbine enhancement project with increased lake storage
4. The SCADA project with increased lake storage (without the turbine enhancement)
5. The SCADA project, increased lake storage, and the turbine enhancement project

Scenario 1. Actual 2003 Operation

With the limited storage available in Lake Kaweah prior to the spillway height increase, the highest releases occurred in May through early June 2003 to prevent emergency spill at Terminus Dam.

Figure 1 shows the actual inflow and storage in Lake Kaweah and releases from Terminus. Also shown in Figure 1 is the "2003 Guidelines for maximum allowable storage by the U.S. Army Corp of Engineers." The Corp of Engineers has rules allowing these guidelines to be surpassed during certain times of the year.

Historically, storage has been utilized in the early-to-mid portion of the growing season. Releases typically end in late July or early August (depending on the water year) and water users then must rely on groundwater for the remainder of the growing season.

Average June-September 2003 peak load generation measured by SCE was 7.04 megawatts (MW).

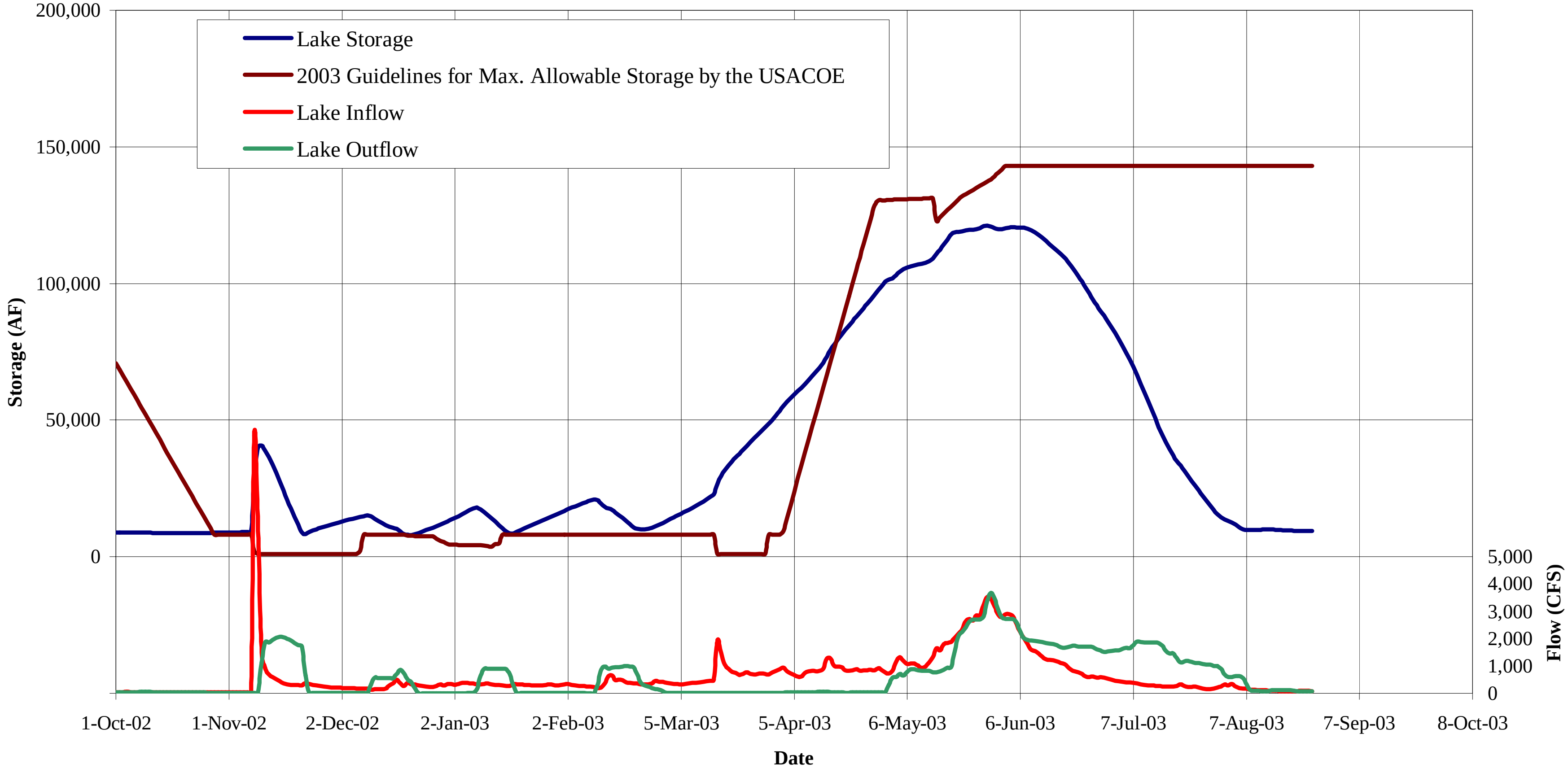

Figure 1. Actual 2003 daily average inflow and storage in Lake Kaweah and daily average outflows from Terminus Dam.

<u>Scenario 2. Potential Modified Releases and Generation due to Increased Lake Storage *ONLY*</u>

With the additional storage created by increasing the height of the spillway, KRPA will have the ability to store more inflow for release later in the season. For example, the actual releases from Terminus Dam during late spring/early summer 2003 were based on emergency spill prevention, not on water user demand.

KRPA and TID personnel foresee withholding releases until June 1st or as long as storage permits. This will extend the release period, maximizing June-September generation and providing surface water to users later into the summer.

Table 1 displays information that compares key data from 2003 against anticipated operations, due to increased lake storage only. Table 1 is used for Scenarios 2 and 3. Scenarios 4 and 5 will fold in different operations that account for the addition of the TID SCADA system. Each column of Table 1 is explained below:

Column A. The 2003 actual average daily deliveries are shown here. The daily values used to develop these average daily values, together with corresponding water levels and generator curves, were used in generating the peak hour MW generation for Scenario 1.

Column B. Estimated Total Demand Downstream of Terminus. This represents the anticipated average daily demands by users of Kaweah River water, assuming that:

(i) more water is now available due to the new, increased storage that was funded by the US Army Corps of Engineers, *plus*
(ii) water is available from the Friant-Kern Canal.

The total demand by all water users utilizing Terminus Dam releases is estimated to vary between 1,400 and 1,800 CFS June through mid-August. Demand drops in September because irrigation of cotton, the main regional crop, typically stops around that time.

The turbine at Terminus Dam has a capacity of approximately 1,450 CFS; therefore, flow rates above 1,450 CFS cannot be used for generation. If KRPA can restrict releases to 1,450 CFS throughout the peak irrigation season, the water that would have been bypassed can be released later in the season and utilized for power generation. If demand is greater than 1,450 CFS, however, that demand must still be met.

Column C. Estimated Total Demand from TID. According to TID, their users' demand is between 600 and 800 CFS (daily average) during June and July.

Column D. TID Deliveries from Terminus. This is computed as:

Column D = Column C – Column E

Column E. TID Deliveries from Friant-Kern Canal. Tulare ID obtains water from the Friant-Kern Canal as well as from Lake Kaweah. The districts' water rights from the Central Valley Project (Friant-Kern Canal) are:

Class 1 water – 30,000 acre-feet (AF)
Class 2 water – 141,000 acre-feet (AF)

TID receives 100% of its Class 1 water and 10% of its Class 2 water (14,000 AF – a conservative estimate) each year from the Friant-Kern Canal. TID typically receives a total of about 44,000 AF annually from the canal. TID has the capacity to accept approximately 800 CFS from the Friant-Kern Canal.

Since TID is the single largest water user of Lake Kaweah, it is possible to reduce Terminus releases significantly if TID uses Friant-Kern Canal water for a portion of its demand (Friant-Kern Canal deliveries are shown in column 7). The total volume of water used from the Friant-Kern Canal under this scenario would be 40,600 AF. The advantage of timing the Friant-Kern Canal releases this way is to avoid Terminus Dam releases that are much greater than the generation capacity.

Column F. The last column in Table 1 shows the estimated releases from Terminus Dam with the Friant-Kern Canal water supplementing a portion of TID demand from June through September (this will be referred to as the "first release schedule"). June releases are greater than 1,450 CFS to prevent emergency spill from Terminus and meet a high demand during this period. However, in July and August the supplemental supply offsets the high demand, maximizing generation and lengthening the delivery season.

Table 1. Estimated new demand and deliveries (in average CFS per day) from Terminus Dam and Friant-Kern Canal with additional lake storage. Used for Scenarios 2 and 3. (Note – estimated releases shown in this table are later modified when the SCADA project is also considered).

Date		- A – 2003 Approximate Actual Average Daily Deliveries	- B – Estimated **Total Demand** Downstream of Terminus for all users (with New Storage)	- C – Estimated Total Needs by TID only	- D – Terminus releases specifically for TID *D = C - E*	- E – TID Deliveries from Friant-Kern Canal	- F – Estimated RELEASES for all customers from Terminus, with Friant-Kern Supplementing TID Demand *F = B - E*
May	**First half**	800	500	200	200	0	500
May	**Second half**	3000	1200	500	500	0	1200
June	**First half**	1800	1800	800	800	0	1800
June	**Second half**	1500	1700	750	550	200	1500
July	**First half**	1800	1650	700	500	200	1450
July	**Second half**	900	1500	700	650	50	1450
Aug	**First half**	250	1400	700	700	0	1400
Aug	**Second half**	0	1200	600	600	0	1200
Sept	**First half**	0	700	600	200	400	300
Sept	**Second half**	0	550	550	50	500	0
					Total AF from Friant-Kern Canal	40,600	

The simulation model was used to estimate the amount of peak load generation using 2003 inflow data with the 2003 discharge schedule from Column F, Table 1. The simulation was run utilizing turbine data acquired prior to the turbine enhancement project on a daily basis. The total volume of water that was released from Terminus in the Scenario 2 simulation matches what was actually released in 2003. However, in the Scenario 2 simulation it was released over a longer period of time because of the increase in Lake Kaweah storage.

Figure 2 shows the lake and dam data utilized for the Scenario 2 simulation. Notice the releases and storage differences as compared to those in Figure 1. Also shown in Figure 2 is the "2004 (New) Guidelines for maximum allowable storage by the U.S. Army Corp of Engineers."

The estimated average peak load generation for Scenario 2 from June 1st through September 30th for the storage project only was 11.89 MW, approximately **4.8 MW** more than actually achieved in 2003. This increase is due to optimizing generation by limiting releases to 1,450 CFS when possible and utilizing Friant-Kern Canal water to make up the difference in demand.

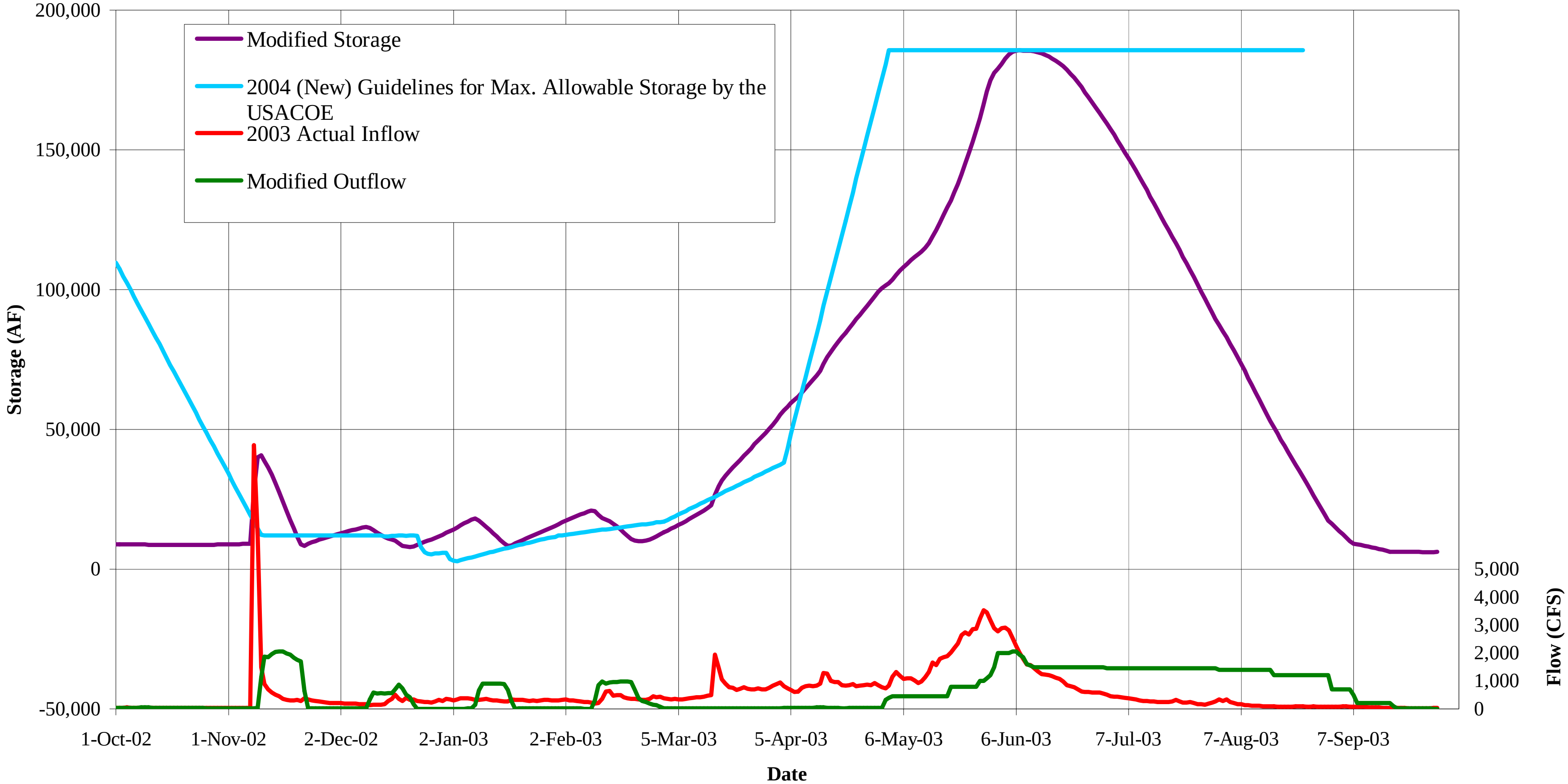

Figure 2. Modified Lake Kaweah storage and Terminus Dam releases based on operation with increased lake storage. Used for Scenarios 2 and 3.

Scenario 3. Peak Load Generation with (i) the Turbine Enhancement Project, plus (ii) Increased Lake Storage

The Terminus dam release simulation for Scenario 2 (Column F, Table 1) was used a second time, using turbine curves from after the turbine enhancement project. The turbine enhancement project incorporated modifications to the turbine allowing it to utilize the increased reservoir water level (increased head on the turbine). The project effectively increased the maximum generated load potential to over 20 MW, compared to a Scenario 2 maximum of 17.85 MW. The turbine flow rate capacity remains approximately 1,450 CFS.

The average peak load generated from June 1st through September 30th due to the turbine enhancement project and the increase in lake storage was 12.62 MW. This indicates an increase in peak generation of **0.74 MW** compared with the increased lake storage project alone.

Scenario 4. Further Modification to Terminus Releases and Generation with the SCADA Project and Increased Lake Storage (*Without* the Turbine Enhancement)

The addition of the TID SCADA project allows KRPA and TID to modify the release schedule even further than seen in Table 1. In Scenario 2 (Storage-Only) the operation parameters were based on maximizing peak generation by limiting releases to 1,450 CFS (or to the demand if the demand was less than 1,450 CFS) when feasible. However, under Scenario 2 the 1,450 CFS must be delivered 24 hours a day even though the peak period is only 6 of the 24 hours. Without the SCADA project TID does not have the ability to handle more than one flow change a day.

With the incorporation of the TID SCADA project (Scenario 4), daily average releases can be limited even further based on two factors:

1. Friant-Kern Canal water will be used to make up the difference between the daily average releases from Terminus and TID's daily average demand.
2. With the SCADA project TID has the ability to handle multiple flow changes from Terminus Dam in a single 24-hour period. Specifically, releases will be scheduled to maximize the noon-6 p.m. peak period and will be reduced during the off-peak period.

The operational objectives of Scenario 4 are as follows:

1. Extend the irrigation season as long as possible, thereby minimizing peak hour pumping by farmers who would need to revert to groundwater supplies.
2. Maintain as high a generator flow rate as possible (but below 1450 CFS) between noon-6 pm, but reduce flow rates during other hours of the day to keep as much water as possible in storage. The dam's operational parameters are no longer based on obtaining a **daily average** release of 1,450 CFS during noon-6 pm to maximize peak generation. With the SCADA project, 1,450 CFS will be released through the turbine (at least from June-August) regardless of the daily average release.
3. Do not fluctuate the generator flows more than TID is capable of absorbing

Table 2 shows the potential release schedule for Scenario 4, resulting from the increase in reservoir storage plus the SCADA project. The major difference in Table 2 compared with Table 1 is the timing of the utilization of Friant-Kern Canal water. Friant-Kern Canal water is used more rigorously in the July and August period, decreasing the daily average release from Terminus. This extends the releases even further into the season, allowing higher peak load generation.

Table 2. Modified Terminus Dam Releases for Scenarios 4 and 5 – Increased Storage plus TID SCADA.
***Average* daily flow rates, CFS.**

Date		2003 Approximate Actual Average Daily Deliveries	Estimated Total Average Demand Downstream of Terminus (with New Storage)	Estimated Total Average Needed by TID from all sources	TID Average Demand from Terminus	TID Average Demand from Friant-Kern Canal	Estimated Releases to all Users from Terminus, with Friant-Kern Supplementing TID Demand
		CFS	CFS	CFS	CFS	CFS	CFS
May	**First half**	800	500	200	200	0	500
May	**Second half**	3000	1200	500	500	0	1200
June	**First half**	1800	1800	800	800	0	1800
June	**Second half**	1500	1700	750	550	200	1500
July	**First half**	1800	1650	700	400	300	1350
July	**Second half**	900	1500	700	400	300	1200
Aug	**First half**	250	1400	700	450	250	1150
Aug	**Second half**	0	1200	600	450	150	1050
Sept	**First half**	0	700	600	600	0	700
Sept	**Second half**	0	550	550	550	0	550
					Total AF from Friant-Kern Canal	36,900	

The volume of water delivered to meet demand from Terminus and the Friant-Kern Canal is essentially the same as in Table 1. The difference is in the utilization of source water to meet that demand. Figure 3 shows the new daily storage and average daily release from Terminus. At first glance, Figures 2 and 3 appear identical. However, by looking closely at the modified lake storage and outflow after July in Figure 3, it becomes apparent that for Scenario 4, the lake storage remains higher for a longer period during the summer, increasing the number of peak days that the turbine is operational during the season.

Peak and Off-Peak Operation in Scenarios 4 and 5.

Figure 4 illustrates in more detail the difference in flow rate from Terminus during the peak and off-peak periods compared to the daily average deliveries. The peak flow will be released from noon to 6 p.m. and the off-peak flow will be released during the remainder of the day. The peak releases remain at 1,450 CFS for a much longer period of time (compared to Scenarios 1-3) because of the SCADA project. In turn the average peak generation is significantly greater compared to the increase in lake storage alone. The average peak generation from June 1st to September 30th for the SCADA project plus increased storage is 14.169 MW, **2.28 MW** greater than storage increase alone (note: the 2.28 MW does not yet include turbine enhancement).

Once releases decline significantly in September, the peak discharges decline to approximately 1,000 CFS (Figure 4). Capacity constraints in TID will limit the flow rate that can be delivered. This is illustrated in Table 3. Historically, bottlenecks in the TID delivery system limited maximum inflows to approximately 800 CFS. However, as part of the TID SCADA project these bottlenecks were removed, increasing the capacity between TID's intake from the river and their storage reservoirs to approximately 1,000 CFS (estimated).

Table 3 also shows the amount of storage that TID will need to store the peak flows so they can be used during the off-peak period. Storing 225 AF of water will be accomplished utilizing Creamline and Tagus reservoirs, which have an approximate combined surface area of 200 acres.

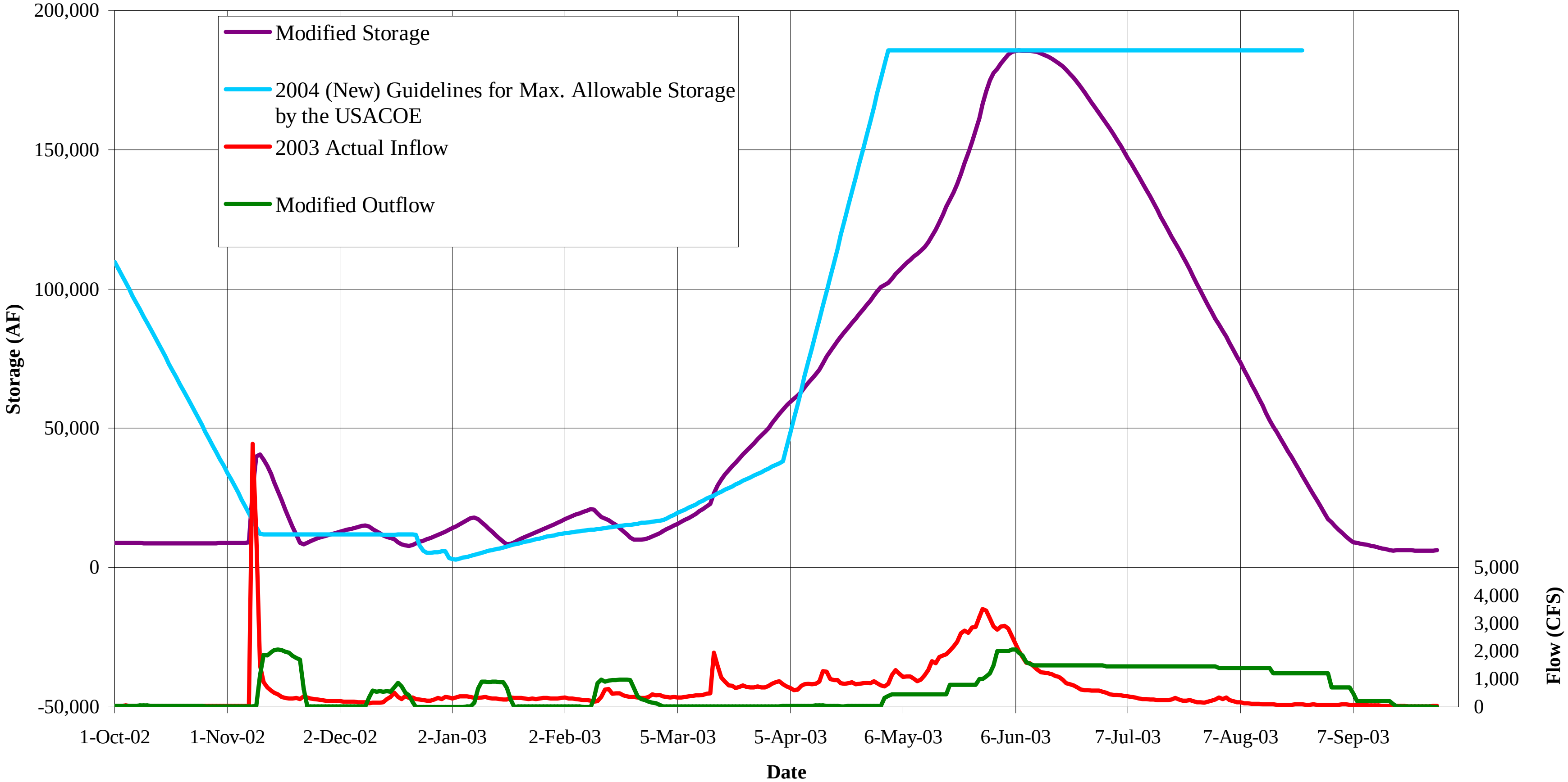

Figure 3. Terminus storage and average daily release for the water year with increased reservoir storage <u>and the TID SCADA project.</u>

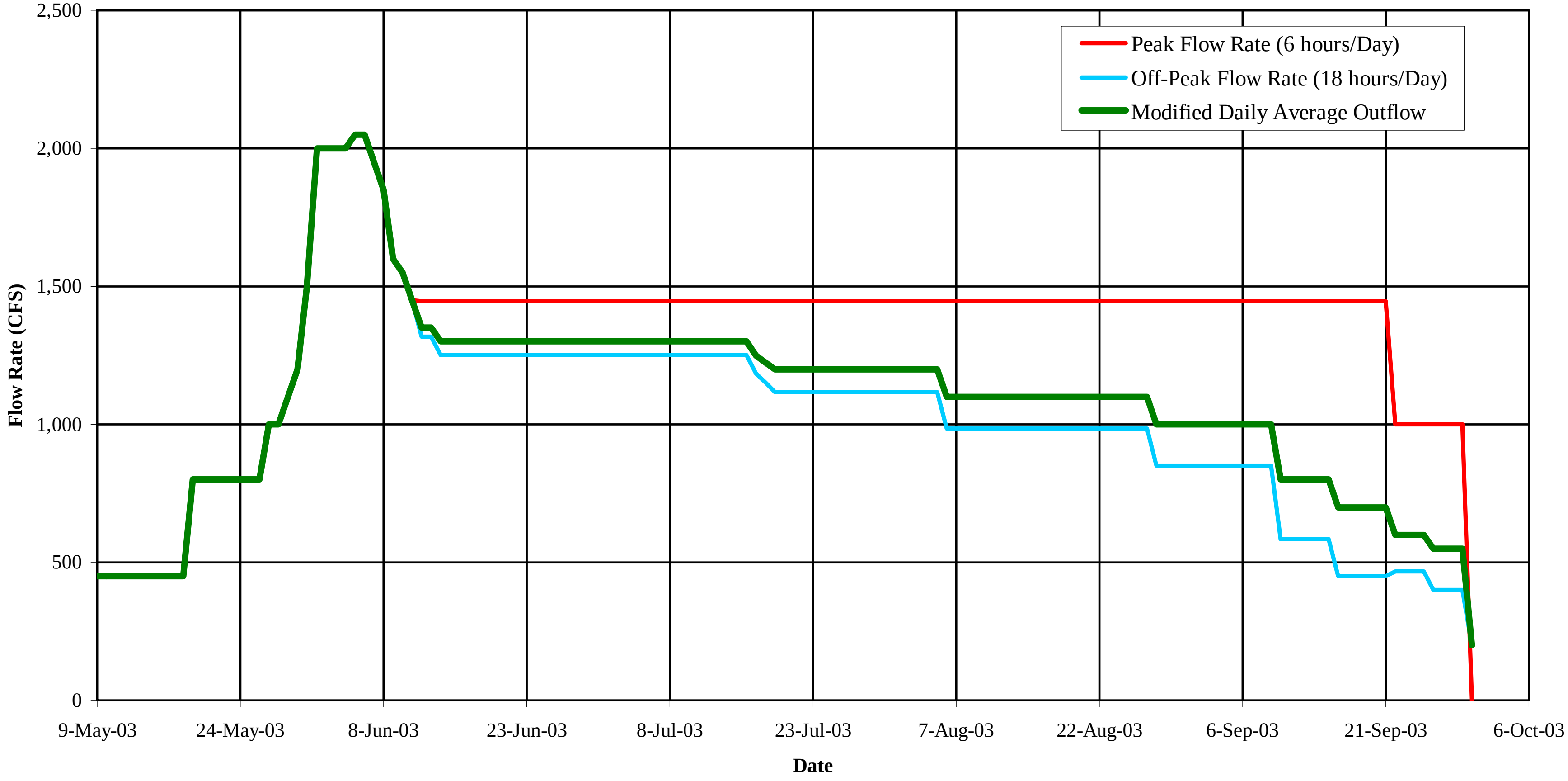

Figure 4. Daily average release from Terminus Dam compared to the daily peak and off-peak releases.

Table 3. Tabular comparison of peak and off-peak flows indicating the swing in flow rate and the amount of TID storage needed to store the peak flow.

		2003 Approximate Actual Average Deliveries	Estimated Average Daily Dam Flow with new storage and SCADA	Estimated Peak Dam Flow (noon-6pm) with new storage and SCADA project	Estimated Off-Peak Dam Flow (18 hours) with new storage and SCADA project	Estimated Peak Dam Flow **to TID** (noon-6pm) with new storage and SCADA project[1]	Estimated Off-Peak Dam Flow **to TID** (18 hours) with new storage and SCADA project	Acre-feet that must be buffered by TID on a daily basis
Date		CFS	CFS	CFS	CFS	CFS	CFS	AF
May	**First half**	800	500	500	500	200	200	0
May	**Second half**	3000	1200	1200	1200	500	500	0
June	**First half**	1800	1800	1800	1800	800	800	0
June	**Second half**	1500	1500	1500	1500	550	550	0
July	**First half**	1800	1350	1447	1318	497	368	49
July	**Second half**	900	1200	1447	1118	647	318	124
Aug	**First half**	250	1150	1447	1051	747	351	149
Aug	**Second half**	0	1050	1447	918	847	318	199
Sept	**First half**	0	700	1100	567	1000	467	200
Sept	**Second half**	0	550	1000	400	1000	400	225

[1] The maximum flow rate into the TID main canal is limited to 1000 CFS. Therefore, the August peak flow rates to TID equal 1000 CFS minus the flow rate from the Friant-Kern Canal.

Scenario 5. Increased Generation with (i) SCADA, (ii) Increased Lake Storage *and* (iii) the Turbine Enhancement Project

The final step in the verification process was to incorporate the turbine enhancement project into the Scenario 4 Terminus Dam flow release schedule. The simulation was run a final time utilizing the same release and storage data used in section 4 with the new turbine data. The average June 1st to September 30th peak generation was 15.35 MW with Scenario 5. This was an increase of **1.18 MW** in average daily peak hour generation from Scenario 4.

On-Farm Benefits

Another benefit with the SCADA project includes extending the surface water deliveries into September, thereby reducing groundwater pumping requirements on-farm. Historically, Terminus deliveries continued until early to mid August depending on the water year. Water users are then required to pump groundwater to satisfy late season demand. With the storage project (Scenario 1) deliveries are estimated to continue until late August. The addition of the SCADA project (Scenario 4 and 5) is expected to prolong Terminus releases through the end of September during a typical year. This would decrease the amount of groundwater pumping required by water users.

The amount of peak load reduction due to the decrease in groundwater pumping was estimated utilizing average pumping plant efficiency, average pump TDH, and the estimated percent of electric pumps for the region. This data was obtained from the *California Agricultural Water Electric Energy Requirements* (CAWEER) report prepared by the ITRC for the California Energy Commission in December 2003.

From CAWEER report, Terminus Dam water users are located in region 12a, which encompasses the east side of the San Joaquin Valley from Stanislaus County through Tulare County (minus Madera and Fresno Counties). The average estimate on-farm pumping plant efficiency in 12a is 52.3%. The average estimated total dynamic head (TDH) in 12a is approximately 186 feet (CAWEER Table 15). However, more detailed analysis of TDH values from on-farm pumps tested in Tulare County (only) show an average TDH value closer to 120 feet. The table below shows the data used to estimate the peak load reduction due to decreased groundwater pumping.

Table 4. Average pumping data and estimated conveyance efficiency used to estimate peak load reduction with decreased groundwater pumping.

Est. Conveyance Efficiency	70.0	%
On-Farm Pumping TDH*	120.0	feet
On-Farm Pumping Plant Efficiency*	52.3	%
Percent Electric Pumps On-Farm*	80	%

*Data obtained from the *California Agricultural Water Electric Energy Requirements* Report

The following is an example peak load reduction calculation for and average daily dam flow of 550 CFS:

Average on-Farm Deliveries (Terminus outflow, minus conveyance losses):

$$[550\text{ CFS} \times \left({}^{70\%}\!/_{100\%}\right) \times 449\text{ GPM/CFS} = 172{,}865\text{ GPM}$$

Flow rate that would be pumped from the groundwater using electricity:

$$\text{GPM} = (80\%/100\%) \times 172{,}865\text{ GPM}$$

$$= 138{,}292\text{ GPM}$$

MW required to pump this flow rate:

$$\text{MW} = \frac{138{,}292 \text{ GPM } \times 120' \times .000746 \text{ MW/HP}}{3960 \times {}^{52.3\% \text{ PP Efficiency}}\!/_{100}}$$
$$= 5.98 \text{ MW}$$

In this example 5.98 MW of load would be reduced through a decrease in on-farm pumping with 550 CFS outflow from Terminus Dam. This calculation was made on a daily basis from late August-September using average daily Terminus Dam flows from the simulation. The decrease in peak pumping is estimated at approximately an average of 8.24 MW during late August-September, which averages to **2.04 MW** over the complete period of June-September.

Summary

The following table summarizes the five sections of the verification process. It was determined that over twice the peak load can potentially be generated with the increase in lake storage, the SCADA project, and the turbine enhancement project combined if dam releases are managed in a specific manner.

Table 5. Summary of the average peak load generated from June 1st to September 30th under each scenario.

Scenario	Description	Average Peak MW
1	2003 Actual	7.044
2	Storage only	**11.885**
3	Storage + turbine enhancement	12.621
4	Storage + SCADA	14.169
5	Storage + SCADA + turbine enhancement	**15.352**

Since the increase in spillway height was not part of the CEC APLRP, the baseline average peak load used for verification purposes is 11.885 MW, which takes the height increase into account, not 7.044 MW. Also, since the turbine enhancement project and the SCADA project work in conjunction, the scenario 3 simulation (storage + turbine enhancement) will be ignored for verification purposes. The following table shows the average peak load above baseline credited to each project.

Table 6. Peak load verification summary.

Description	Average Peak MW Credited to each APLRP Project	Average Peak MW Needed for Full Grant Payment
Baseline = 11.885 MW		
TID SCADA Project (14.169 MW – 11.885 MW)	2.28	2.00
KRPA Turbine Enhancement Project (15.352 MW – 14.169 MW)	1.18	1.17
Average On-Farm Peak Load Reduction	2.04	
Total Increase in Peak Load Generation, or on-farm Peak Load Reduction from APLRP Projects	**5.51**	**3.17**

ATTACHMENT D-1
Simulation Development and Verification of Accuracy

Historical daily reservoir data, the turbine generation table, and the Lake Kaweah reservoir elevation-storage table were given to ITRC by KRPA. This data was incorporated into a spreadsheet model to calculate the average megawatt-hours (MWH) generated at Terminus Dam.

Water year data was used in the simulation model. A water year starts on October 1st of the previous calendar year and continues through September 30th of the current year (for example, water year 2003 starts on October 1, 2002 and ends on September 30, 2003). The only data that was of interest for verification was June 1st – September 30th.

Once the spreadsheet model was completed, June – September 2003 data was used to check the model for accuracy. Measured generation data at Terminus Dam obtained from Southern California Edison (SCE) was compared with generation data calculated in the spreadsheet. The results of this comparison are shown below.

Table 7. June – September 2003 actual average MW generated compared to the calculated average MW generated

	Actual	Calculated	Difference
Megawatts	**7.044**	**7.191**	**0.147**

The 0.14 MW difference is attributed to transformer losses before the SCE meter readings. KRPA estimates that the measured generation is 97.7% of the calculated generation on a daily basis because of the transformer losses. The following table shows the load generation value after correcting the simulation.

Table 8. June – September 2003 actual average MW generated compared to the calculated average MW generated (corrected)

	Actual	Calculated	Difference
Megawatts	**7.044**	**7.034**	**-0.010**

The daily calculated values were corrected for transformer loss by multiplying the initial value by 0.977. All values shown in this memo incorporate this correction.

APPENDIX E

CASE STUDIES